Zargon

ENERGY TRUST

Building a sustainable trust

2004 ANNUAL REPORT

Same strategies,

same properties,

similar risk/reward tolerance,

same board,

same staff.

Different structure.

Zargon Energy Trust (the "Trust") was created from the acquisition of all of the operational, financial and intellectual assets of Zargon Oil & Gas Ltd. on July 15, 2004. The Trust has been designed to be a sustainable trust, meaning that Zargon expects to indefinitely maintain stable production, reserves and distributions on a per trust unit basis, while distributing fifty percent of our cash flows attributed to our unitholders. This sustainability objective is to be accomplished with ongoing capital programs funded by the remaining fifty percent of our trust's cash flows. In addition to our sustainability strategy, our business model calls for a modest level of growth on a per trust unit basis through capital programs funded from cash flows attributable to our exchangeable shares, the cautious use of unutilized bank lines and/or accretive equity issues.

The Trust will build on the business philosophies of our predecessor company, Zargon Oil & Gas Ltd., that were successfully followed over its value-seeking twelve-year history. The Trust will continue to pursue the complementary business strategies of first, exploring and developing natural gas reserves, while second, exploiting existing oil reservoirs. These initiatives will be supported by Zargon's extensive 376 thousand net acre undeveloped land base and by Zargon's portfolio of Williston Basin underdeveloped oil properties containing 174 million barrels of working interest oil-in-place.

Zargon's trust units trade on the Toronto Stock Exchange under the symbol ZAR.UN.

trust highlights

	2004	2003	Percent Change
FINANCIAL ($ million, except per unit amounts)			
Income and Investments			
Petroleum and natural gas revenue	**124.0**	101.7	22
Cash flow from operations	**63.7**	54.3	17
Cash distributions	**10.7**	–	–
Net earnings	**20.6**	24.4	(15)
Net capital expenditures	**56.3**	39.9	41
Balance Sheet at Year-End			
Property and equipment, net	**209.7**	167.9	25
Bank indebtedness	**14.2**	7.0	103
Unitholders' equity	**120.6**	112.5	7
Total units outstanding (million)	**18.61**	17.99	3
Per Trust Unit, Diluted			
Cash flow from operations	**3.40**	2.96	15
Net earnings	**1.20**	1.33	(10)
Cash Distributions ($/trust unit)	**0.70**	–	–
OPERATING			
Average Daily Production			
Oil and liquids (bbl/d)	**3,416**	3,287	4
Natural gas (mmcf/d)	**28.84**	24.95	16
Equivalent (boe/d)	**8,222**	7,446	10
Equivalent per million total units (boe/d)	**447**	418	7
Average Selling Price (before hedges)			
Oil and liquids ($/bbl)	**45.37**	36.66	24
Natural gas ($/mcf)	**6.37**	6.33	1
Proved and Probable Reserves (year-end)			
Oil and liquids (mmbbl)	**14.36**	13.56	6
Natural gas (bcf)	**69.56**	67.07	4
Equivalent (mmboe)	**25.95**	24.74	5
Equivalent per total unit – year-end (boe)	**1.39**	1.38	1
Wells Drilled, Net	**49.5**	38.6	28
Undeveloped Land (thousand net acres)	**376**	398	(6)

Notes: Throughout this report, the calculation of barrels of equivalent (boe) is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil.

Average daily production per million total units is calculated using the weighted average number of units outstanding during the period, plus the weighted average number of exchangeable shares outstanding for the period converted at the exchange ratio at the end of the period.

Cash flow from operations is a non-GAAP term that represents net earnings for non-cash items. For a further discussion about this term, refer to page 27 of the report.

Total units outstanding include trust units plus exchangeable shares outstanding at period end. The exchangeable shares are converted at the exchange ratio at the end of the period.

Certain comparative period numbers reflect retroactive restatement due to a change in accounting policy.

president's message

ZARGON **EXPERIENCED SIGNIFICANT** STRUCTURAL CHANGE AND **EXCELLENT FINANCIAL AND OPERATING RESULTS** IN 2004.

The Year In Brief

The year included significant structural change and excellent financial and operating results. In mid-2004, Zargon Energy Trust was initiated as a sustainable energy trust by acquiring all of the assets of Zargon Oil & Gas Ltd., while on an operating level, the year set new highs for production volumes, revenue and cash flow. The Trust, having acquired all of its predecessor Company's operational, financial and intellectual assets, is proceeding in a tax-efficient format on the business model that Zargon Oil & Gas Ltd. followed successfully for twelve years. **With this model, the Trust anticipates that it can maintain stable production, reserves and cash distributions on a per total trust unit basis with a fifty percent cash distribution policy.** The Zargon trust concept has to date been well-received by the investment community.

Zargon reported strong gains in 2004 both operationally and financially, setting new financial highs led by oil prices that reached and sustained record levels. Compared to the prior year, natural gas volumes increased 16 percent and oil and liquids volumes increased four percent. Revenue climbed 22 percent, cash flow from operations increased 15 percent to $3.40 per diluted unit, while net earnings remained high, but decreased 10 percent to $1.20 per diluted unit due to several unrelated reasons.

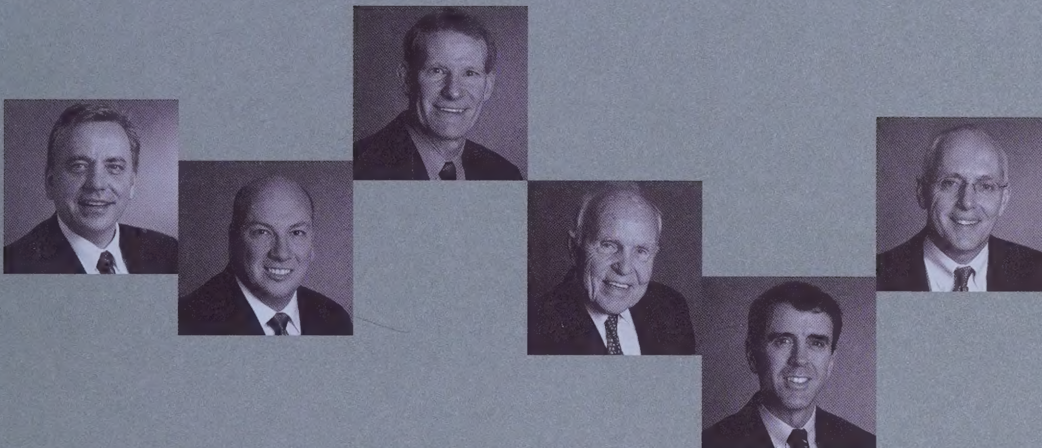
The excellent 2004 cash flow from operations of $63.75 million, combined with a strong balance sheet, enabled the Trust to carry out its record $56.27 million capital program, allocating $44.46 million to exploration and development and $11.81 million to oil property acquisitions. In addition to the capital program, the Trust distributed $10.70 million in distributions to unitholders and paid out a total of $9.44 million in one-time charges related to the trust conversion and options buyout. These combined cash outflows of $76.41 million were met with a moderate $10.27 million increase in net debt (bank debt, net of working capital), approximately equal to the one-time charges. Net debt at year-end was $23.37 million, equivalent to less than five months of 2004 cash flow. The Trust plans to maintain it's very strong balance sheet, that has been a characteristic of Zargon's history, as a buffer for short-term changes and a support for strategic moves.

Sustainable Trust Strategies

Zargon's historical successful corporate strategies will be continued by the Trust, but modified to recognize that the impending income tax burden has been replaced by a defined pattern of high priority cash distributions to unitholders. We have structured our new trust as a sustainable energy trust. **To Zargon, a sustainable trust is defined as a Trust that has a sufficient capital reinvestment program to indefinitely maintain reserves, production and distributions on a per trust unit basis. This sustainability objective must be accomplished without the deterioration of the underlying quality of assets or the deterioration of the Trust's financial condition.** Based on its existing asset mix, Zargon plans to meet its sustainability targets with exploration and development capital programs funded from fifty percent of its cash flows.

At current production levels of approximately 8,500 barrels per day, the exploration and development programs funded from fifty percent of Zargon's corporate cash flow must annually replace 3.1 million barrels of proved and probable reserves. Essentially, the Trust needs to find two barrels of reserves using the cash flow from one barrel of production, which

The reorganization of Zargon Oil & Gas Ltd. into Zargon Energy Trust has been accounted for using the continuity of interest method. Accordingly, all financial and operating data for the year ended December 31, 2004, is presented as if Zargon Energy Trust had always carried on the business of Zargon Oil & Gas Ltd.



Craig Hansen Brent Heagy **ZARGON'S**
Dan Roulston John McCutcheon **SENIOR**
Ken Young Mark Lake **MANAGERS**

implies that Zargon's exploration and development capital programs must deliver a corporate recycle ratio of two. Over the last six years, Zargon's recycle ratio has shown substantial volatility with most years below the target threshold of two. However, if the years since 1999 are grouped together as a whole, the ratio of two was achieved despite suffering through a large negative reserve revision in 2003, related to the implementation of the new reserves reporting standard, National Instrument 51-101. **Although it is anticipated that there will continue to be year by year variances in the efficiencies of Zargon's exploration and development capital programs, the long-term delivery of an average recycle ratio of two will be a fundamental and necessary target of our sustainable trust strategy.**

In addition to maintaining stable reserves per trust unit, the sustainable trust model requires Zargon to maintain stable production rates on a per trust unit basis. Currently, Zargon's oil and natural gas production from producing wells declines at annual rates of 10 percent and 23 percent, respectively. Based on these proved producing decline rates, Zargon must add approximately 1,500 barrels of equivalent per day of new production every year to replace the naturally occurring production declines. Similar to the reserve replacement requirements, these production additions need to be replaced with exploration and development programs funded from fifty percent of our cash flow.

The calculations for the production addition parameters essentially parallel the proved and probable reserve addition parameters. Based on 2004 cash flows, the Trust's sustainability model requires that new production is added at a cost of $21.2 thousand per barrel of equivalent per day. Over the last six years, Zargon has regularly met this target with the exploration and development component of its capital budget. The long-term delivery of efficient production addition costs is a second fundamental and necessary target of our sustainable trust strategy.

In addition to our sustainability strategy, our business model also calls for a modest level of growth on a per trust unit basis through capital programs funded from the balance sheet. Specifically, this additional capital is sourced from the use of cash flows attributable to our exchangeable shares, the cautious use of unutilized bank lines and/or from accretive equity issues. This capital will generally be directed to acquisitions focused on the replenishment of our feedstock of undeveloped natural gas exploration acreage or our feedstock of underdeveloped oil exploitation properties. As these acquisitions will not be funded by cash flow; they will be subject to different investment criteria than our exploration and development programs. More specifically, instead of meeting the sustainability targets, the capital programs sourced from the balance sheet must provide sufficient resources of undeveloped land or underdeveloped oil properties that can support future exploration and development programs that meet our sustainability criteria.

HISTORY OF PERFORMANCE 2004 highlights KEY ACHIEVEMENTS

Zargon Energy Trust is proceeding with the business model that Zargon Oil & Gas Ltd. followed successfully for twelve years.

Over its history, Zargon Oil & Gas Ltd. monitored its progress by measuring four key parameters on a per share basis: reserves, production, cash flow from operations and net earnings. Using these parameters, the Trust's predecessor company generated the following growth rates:

- An exceptional 24 percent annual per share growth rate for our entire twelve-year history, and a 36 percent annual growth rate over the final six years for the four key parameters.
- Considering only the fundamental, non-financial and non-price dependent parameters of reserves and production, Zargon's growth per share averaged 15 percent per year over its twelve-year history and 14 percent per year over the last six years.

As Zargon moves forward into the future in a new trust format, we will continue to build on our record of efficiencies outlined below:

- Forty-five consecutive quarters of positive net earnings; a record that we believe will be extended into the foreseeable future.
- Over our history we have raised a total of $45 million of share or unitholder equity. From this investment, we have delivered more than $84 million of retained earnings and have built a business entity with a market capitilization more than $450 million.

Zargon's successful conversion to a sustainable income trust in mid-year was the most significant event in 2004.

- Zargon's mid-year trust conversion provided a robust operating and financial platform that will be the foundation of a long-lived sustainable trust. By retaining all of the properties, intellectual resources and financial strength of the predecessor company, Zargon is able to continue its business plan into the future while distributing surplus cash to its unitholders.
- On a per total trust unit basis, Zargon's 2004 production averaged 447 barrels of equivalent per day per million trust units, a seven percent gain over the prior year.
- On a per total trust unit basis, Zargon's 2004 year-end proved and probable reserves were 1.39 barrels of equivalent per trust unit, a one percent gain over the prior year.
- Including future capital costs, Zargon's 2004 capital investment programs delivered a moderately disappointing finding, development and acquisition cost of $13.72 per barrel of equivalent. For 2005, Zargon anticipates improved finding and development costs from its exploration and development capital programs.

Mode of Operations

Over its twelve-year life, the two distinct complementary initiatives of the efficient exploitation of oil properties and the seismically-driven exploration for natural gas reserves have facilitated Zargon's success. Our large inventory of underdeveloped oil properties and undeveloped land provides Zargon the resource base to continue with these initiatives throughout the foreseeable future.

Our oil exploitation business begins with the identification and acquisition of properties with a large oil-in-place that are generally located in the Williston Basin. We then deploy improved recovery techniques or geologically driven exploitation concepts to develop additional reserves. **Through numerous property and corporate acquisitions over its history, Zargon has assembled a working interest inventory of 174 million barrels of exploitable oil-in-place in the Williston Basin core area.**

Historically, our Williston Basin capital programs have provided efficient reserve and production additions. Specifically, in the last three years, Zargon has deployed a $40.94 million ($22.82 million excluding acquisitions) capital program on Williston Basin oil assets. During this period, the Williston Basin's production grew from 2,151 barrels per day to 2,643 barrels per day. The three-year weighted average proved and probable finding and development cost, including acquisitions, was a very strong $8.09 per barrel of equivalent. Including acquisition costs, the three-year statistics for production addition costs, were $25.0 thousand per barrel of equivalent per day. Excluding acquisition costs, the three-year statistics for production addition costs were $19.0 thousand per barrels of equivalent per day. **In 2005, we plan on expanding our Williston Basin exploitation programs with a 12 net well, $15 million capital investment program.**

Our natural gas exploration business explores for shallow and medium depth natural gas reservoirs based on seismic, geological, and occasionally reservoir engineering concepts. Our strategy is to acquire large contiguous land blocks with multi-zone potential and reduce exploration risk by applying advanced seismic and detailed geological mapping. The resource inputs for our natural gas exploration business are seismically or geologically prospective undeveloped lands, preferably in areas where we control natural gas facilities. Through Crown sale undeveloped land purchases, we have expanded our natural gas exploration and development activities from primarily the Alberta Plains to include selected areas of West Central Alberta.

The Alberta Plains area represents 46 percent of Zargon's production (3,765 barrels of equivalent per day in 2004) and has provided stable production volumes in recent years. **Historically, the Alberta Plains capital programs have provided efficient reserve and production additions from the exploration and development of the 146,000 net acre undeveloped land base.** Specifically, in the last three years, Zargon has deployed a $36.20 million Alberta Plains capital program focused on natural gas exploration and development. Despite substantial reserve standard related negative revisions in 2003, this capital program has delivered a three-year weighted average proved and probable finding and development cost of $12.65 per barrel of equivalent. The three-year statistics for production addition costs have averaged a very strong $14.6 thousand per barrel of equivalent per day. **In 2005, we plan on maintaining our Alberta Plains production volumes with a 22 net well, $15 million exploration and development capital investment focused on natural gas.**

In 2004, over 77 percent of Zargon's production and property cash flow was generated in the Williston Basin and Alberta Plains core areas, where we have met or exceeded our sustainability target criteria. In the third core area of West Central Alberta, we did not reach our 2004 sustainability targets with our natural gas exploration programs. The West Central Alberta core area includes Highvale, Pembina and the Peace River Arch exploration properties where we have accumulated an undeveloped land inventory of 185 thousand net acres. As could be expected with "grass roots" exploration activities, our results and efficiencies have varied significantly in the West Central Alberta core area. Following very strong 2003 production addition results, Zargon's 2004 West Central Alberta exploration results did not meet expectations, taking the three-year weighted average proved and probable finding and development cost to $17.78 per barrel and the three-year production addition costs to $29.6 thousand per barrel of equivalent per day. Despite the disappointing 2004 results, Zargon remains enthusiastic about the exploration opportunities on its West Central Alberta undeveloped land base, but the constraints of our new sustainable trust format require us to reduce the variability of our capital program results.

OPERATING 2004 highlights FINANCIAL

OPERATING

Capital expenditures in 2004 totalled $56.27 million, with $44.46 million allocated to exploration and development activities. Operating highlights included:

- Drilled a 49.5 net well program, with an 85 percent success rate, that delivered 35.4 net natural gas wells and 5.7 net oil wells.
- Reflecting some expiries and a more selective acquisition program during this high-cost period, Zargon's undeveloped land decreased six percent to 376 thousand net acres. Despite this reduction, Zargons' undeveloped land to production ratio of 46 net acres per barrels of equivalent per day remains in the top quartile of our trust peers.
- Natural gas production grew 16 percent to 28.84 million cubic feet per day.
- Oil and liquids production increased four percent to 3,416 barrels per day.
- Proved and probable reserves increased by five percent to 25.95 million barrels of equivalent.
- Proved reserves increased two percent to 19.05 million barrels of equivalent, of which 89 percent were classified as proved producing reserves.

FINANCIAL

Increased production volumes supported by much higher oil prices and continuing strong natural gas prices enabled Zargon to establish record levels of revenue and cash flow in 2004.

- Global oil commodity prices reached and sustained new record levels in 2004, providing Zargon with an average oil and liquids price of $45.37 per barrel, an all-time high and 24 percent above 2003.
- The average natural gas price received of $6.37 per thousand cubic feet maintained the historically high level established in 2003. With high prices for both products, revenue and cash flow reached record levels.
- Revenue in 2004 was $124.0 million, 22 percent above 2003 and cash flow from operations was $63.75 million, 17 percent above the prior year. Cash flow was $3.40 per diluted unit in 2004 compared to $2.96 per diluted share in 2003.
- Net earnings for 2004 of $20.63 million or $1.20 per diluted unit were the second highest year on record.
- A total of $10.70 million was distributed to unitholders at the rate of $0.14 per trust unit per month for the five months subsequent to the July 15, 2004 conversion to an income trust.

This necessary adjustment will be accomplished by high-grading our existing drilling program and by bringing in financial partners on a promoted basis to help drill some of the higher-risk but higher-reward opportunities. **In 2005, we plan a reformatted West Central Alberta natural gas exploration program entailing 12 net wells and a $10 million capital investment.**

As evidenced by our forty-five consecutive quarters of positive earnings, Zargon has developed the skills to manage and allocate our investment programs efficiently. A key component of this success is our understanding that our business is built on the two resource feedstocks of undeveloped natural gas exploration lands and underdeveloped oil properties. Over a business cycle, these feedstocks must be replenished at reasonable costs to support future sustainable exploration and development activities. Currently, commodity prices and the related costs of our undeveloped land and underdeveloped oil property feedstocks are, in our opinion, fully priced. Consequently, we will remain cautious about aggressively using our debt or equity capital funding alternatives unless we can confidently forecast long-term quality returns after allowance for the future exploration and development opportunities related to the acquired resource. **We do however, believe that our sustainable trust structure with its substantial ongoing exploration and development budget, provides us with a competitive advantage in acquiring resources that can be converted into reserves and production through additional technical and capital inputs.** Over the last two years, Zargon has approached the property and corporate acquisition markets cautiously with selected but smaller value-added acquisitions. Over the next year, we suspect that with the ever-changing business cycle, new opportunities will present themselves to allow us through property or corporate acquisitions to replenish and expand our resource opportunity base.

Outlook

In the first quarter of 2005, the industry outlook remains very positive with strong natural gas prices and record oil prices. Consequently, the resulting record industry activity levels are creating a high-cost environment for exploration, exploitation and production activities. Also, our industry's ready access to investment capital through equity and debt issues is pushing the costs of property and/or corporate acquisitions and Crown land sales to unprecedented high levels. During this enthusiastic period, Zargon will continue to give priority to the control of costs as it looks to the development of its internal resources for the maintenance of reserves, production and distributions. Importantly, actions taken throughout 2004 and in prior years have successfully provided a multi-year inventory of undeveloped land and oil-in-place feedstocks that will support our exploration, development and exploitation activities through 2006. With a strong balance sheet, record operating cash flows and a refocused $40 million exploration and development budget, we are confident that we will meet our sustainable trust commitments in 2005.

Acknowledgements

We are grateful for the confidence in Zargon displayed by our shareholders as they voted overwhelmingly for conversion to a trust status. We are equally grateful for the commitment of our staff who have almost without exception remained in place after the conversion. We will continue to do our best to reward the trust of both of these constituencies. Our overriding objective continues to be to enhance the value of our unit-holders' investment while minimizing the risk to this investment's integrity. We acknowledge with pleasure the support and counsel of our Board of Directors.

Respectfully submitted,

C.H. Hansen
President and Chief Executive Officer
March 14, 2005

core areas and business strategies

ZARGON'S BUSINESS STRATEGY IS **BUILT ON TWO DISTINCT BUT COMPLEMENTARY INITIATIVES** OF FIRST, THE EXPLORATION AND DEVELOPMENT OF **NATURAL GAS RESERVES** AND SECOND, THE EXPLOITATION OF EXISTING **OIL RESERVOIRS.**

Zargon's activities are located in three core areas with Zargon's natural gas exploration and development business based in the Alberta Plains and West Central Alberta. The Williston Basin core area, in Saskatchewan, Manitoba and North Dakota, provides the foundation for Zargon's oil exploitation business. Each of these businesses, while having common elements, also has distinct characteristics.

NATURAL GAS EXPLORATION AND DEVELOPMENT BUSINESS

Zargon's natural gas exploration and development business is built on two property types.

- First, the Alberta Plains properties are generally more mature natural gas producing areas. These areas provide the majority of the Trust's natural gas production and reserves. This existing production is predominantly high working interest, operated and delivered into company owned production facilities.

- Second, the West Central Alberta properties tend to be natural gas prone areas that are less mature from a development perspective and more exploratory in nature. These properties are focused in three specific areas, where Zargon has accumulated a considerable undeveloped land position.

Zargon's natural gas exploration and development activities are based on geophysical and geological analysis to identify and pursue drilling opportunities on the Trust's undeveloped land resource base. These undeveloped lands are predominantly situated in large, concentrated land blocks, and for the most part this land is accessible for all-season operations.

OIL EXPLOITATION BUSINESS

Zargon's oil business is built on the exploitation of long-life shallow-decline oil properties that are characterized by large under-exploited volumes of oil-in-place. The Zargon oil properties are primarily located in the Williston Basin core area of Southeastern Saskatchewan, Manitoba and immediately across the border in the northern counties of North Dakota. The Trust utilizes reservoir engineering, three-dimensional seismic, horizontal drilling and detailed geological mapping to identify opportunities to increase production and to maximize the ultimate oil recoveries from the properties' oil-in-place resource base. Frequently, the oil exploitation initiatives include the implementation or modification of waterflood projects.

2004 CORE AREA STATISTICAL SUMMARY

	Alberta Plains	West Central Alberta	Williston Basin	Total
2004 Production (boe/d)	3,765	1,814	2,643	8,222
2004 Production Growth (percent)	7	23	8	10
2004 Proved and Probable Reserves (mboe) [1]	9,694	4,166	12,095	25,955
2004 Annual Reserve Growth (percent)	5	(4)	8	5
2004 Undeveloped Land (thousand net acres)	146	185	45	376
2004 Undeveloped Land Growth (percent)	(21)	6	15	(6)
2004 Capital Program ($ million)	14.57	22.12	19.58	56.27
3 Yr. FD&A Cost ($/boe) [2]	12.65	17.78	8.09	11.89
3 Yr. Production Addition Cost ($thousand/boe/d) [3]	14.6	29.6	25.0	22.0

1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The reported proved and probable finding, development and acquisition cost ("FD&A") include an allowance for the change in future capital expenditures.*
3. *The production addition costs are calculated assuming trust average natural gas and oil annual decline rates of 23 percent and 10 percent, respectively.*

Zargon's large Alberta undeveloped land inventory provides the feedstock for exploration and development drilling programs that sustain our natural gas production and reserve volumes. The region is divided into the Alberta Plains and West Central Alberta core areas.

Alberta Plains

The Alberta Plains core area provides substantial cash flows that are approximately equally allocated to trust distributions and to the necessary reinvestment programs required to maintain stable production volumes.

The Trust's Alberta Plains core area is primarily located in the east central region of Alberta and is made up predominantly of relatively shallow natural gas producing properties. This core area provides approximately two-thirds of Zargon's natural gas production and delivers large free cash flows that underpin the Trust's monthly distributions. Stable production volumes are maintained through exploration and development drilling programs on the Trust's existing land base. In 2004, the Alberta Plains core area generated $32.64 million of property cash flow, of which $14.57 million or 45 percent was reinvested in the core area.

During 2004, the Trust concluded a very successful capital program focused on drilling, completions and tie-ins. Despite providing more than $18 million of property cash flow in excess of capital expenditures, the area's year-end proved and probable reserves increased five percent to 9.69 million barrels of equivalent. The core area's production volumes also climbed seven percent in the year to 3,765 barrels of equivalent per day. The Alberta Plains capital programs were very efficient in 2004, providing proved and probable reserve additions at a cost of $7.56 per barrels of equivalent and production additions at a cost of $15.10 thousand per barrel of equivalent per day.

2004 ACTIVITIES

- Shot 202 kilometres of 2D seismic and four square kilometres of 3D seismic.
- Drilled 21.4 net wells resulting in 18.7 net gas wells and 2.7 net dry holes.
- Constructed 21 net kilometres of pipelines, and tied-in 17 net gas wells into existing gathering systems.
- Negotiated nine farm-outs, resulting in third parties drilling 30 wells and shooting two 3D seismic programs on Zargon lands.
- Spent $14.57 million on capital projects, or 45 percent of the Alberta Plains core area's property cash flow.
- Increased Alberta Plains production by seven percent to 3,765 barrels of equivalent per day.

2005 PLANS

- Continue the exploration and development of the large Alberta Plains undeveloped land base by shooting 2D seismic and 3D seismic, drilling wells and optimizing facilities.
- Drill approximately 20 net wells at the Jarrow, Hamilton Lake, Taber and Ukalta properties.
- Reinvest approximately 50 percent of the core area's property cash flow to maintain a stable production base of 3,750 barrels of equivalent per day.

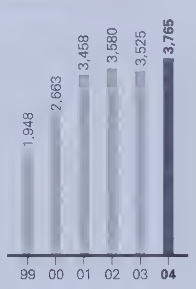
To increase the Trust's returns, Zargon undertook a 2004 farm-out initiative where risk or reward parameters did not meet Zargon's investment criteria. This initiative resulted in the drilling of 30 farm-out wells on Zargon lands, including one exploratory CBM (coal bed methane) test.

ALBERTA PLAINS

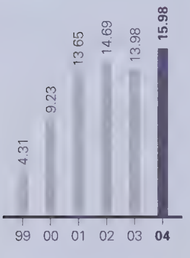
	2004	2003	2002	2001
Average Production				
Oil (bbl/d)	**595**	640	660	716
Natural gas (mmcf/d)	**19.02**	17.31	17.52	16.45
Equivalents (boe/d)	**3,765**	3,525	3,580	3,458
Total Proved & Probable Reserves (1)				
Oil (mbbl)	**1,932**	1,840	2,065	2,127
Natural gas (bcf)	**46.57**	44.01	49.74	52.85
Equivalents (mboe)	**9,694**	9,208	10,355	10,935
Undeveloped Lands				
Net acres (thousands)	**146.0**	185.4	189.3	173.7
Drilling Activities				
Net wells	**21.4**	12.8	14.9	40.5
Capital Expenditures ($ million)				
Net property acquisitions	**0.60**	(1.16)	5.20	(4.90)
Undeveloped land, seismic, geological	**3.09**	3.04	1.48	6.19
Drilling, completion, equipping, facilities	**10.88**	7.39	5.68	16.86
Total expenditures	**14.57**	9.27	12.36	18.15
Capital Program Efficiencies				
Finding, development and acquistion cost ($/boe) (2)	**7.56**	65.03	15.41	21.41
Production addition cost ($thousand/boe/d) (3)	**15.1**	13.6	15.0	13.6

1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The reported proved and probable finding, development and acquistion cost includes an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and changes in reserve definitions.*
3. *The production addition costs are calculated assuming trust average natural gas and oil annual decline rates of 23 percent and 10 percent, respectively. The calculations make the simplifying assumption that all capital expenditures were made at the beginning of the year.*

ALBERTA PLAINS PRODUCTION (boe/d)



JARROW NATURAL GAS PRODUCTION (mmcf/d)



Historically, the Alberta Plains core area capital programs have consistently delivered excellent production addition costs of approximately $15 thousand per barrel of equivalent per day. Despite these very strong production addition costs, the core area's proved and probable finding and development costs have been inconsistent over the last four years, due to the effect of negative reserve revisions coming from changing reserve standards.

Going forward, Zargon has identified sufficient opportunities that should provide stable production volumes through 2006 at a reasonable cost. These opportunities include new exploration plus development drilling programs in each of the following key properties:

JARROW

The Trust's most significant producing gas property is the Alberta Plains Jarrow property. This property is characterized by high working interests, ownership and operatorship of significant pipeline and gas processing facilities and a continuing large inventory of prospects on a 101 thousand net acre undeveloped land inventory.

Since 2001, Zargon's strategy for Jarrow has been to sustain natural gas production levels from this property in the range of 15 million cubic feet per day. This strategy attempts to balance, in a sustainable manner, the efficient loading of the existing infrastructure capacity while capitalizing on the considerable inventory of natural gas prospects.

During the year, the Trust shot 202 kilometres of 2D seismic and one 3D seismic program as part of its ongoing exploration and development programs. The Trust was also successful in identifying new potential in two relatively under-exploited Mannville zones. The Jarrow 2005 capital programs will continue to build on the 2004 successes and will also focus on the exploitation of some larger under-developed existing natural gas pools.

In 2004, Zargon drilled 17 net (21 gross) wells at Jarrow, resulting in 14.8 net natural gas wells and 2.6 net dry holes. The Jarrow property produced an average of 15.98 million cubic feet per day in 2004.

HAMILTON LAKE

Also located in the Alberta Plains core area is the Hamilton Lake property, where Zargon has maintained stable operated natural gas and oil production levels on a large contiguous land block of 24 thousand net acres.

In addition to the Mannville natural gas prospects historically drilled at Hamilton Lake, Zargon has made progress in evaluating an extensive natural gas charged Viking sand. In 2005, Zargon expects to drill a three-well Viking pilot, which, if successful, could lead to a multi-well development program.

Zargon drilled 3.0 net wells in Hamilton Lake in 2004 resulting in three successful gas wells. In addition, 30 wells were drilled on Zargon lands under several farm-out agreements. This includes 22 low-rate wells drilled for the development of the Second White Specs formation where Zargon has maintained a royalty interest.

The Hamilton Lake property provided 2.05 million cubic feet per day and 102 barrels per day of production to Zargon in 2004.

OTHER PROPERTIES

Other significant properties in the Alberta Plains core area are the Ukalta natural gas producing area northeast of Edmonton and the Taber medium gravity oil property of southern Alberta. In 2005, Zargon will proceed with down spacing drilling programs at both of these properties.

West Central Alberta

The West Central Alberta core area provides significant cash flows that have been historically reinvested to explore the area's large inventory of undeveloped lands.

Zargon's West Central Alberta core area is located west of Edmonton in central Alberta and is comprised of three natural gas producing regions that provide the Trust with a varied inventory of exploration opportunities. This core area currently delivers approximately one third of Zargon's natural gas production, and with exploration success provides Zargon with the opportunity to grow its natural gas production volumes. Over the last three years, Zargon has successfully grown the area's production volumes and undeveloped land base almost fourfold and fivefold, respectively. In 2004, Zargon spent $22.12 million of capital in the West Central Alberta core area, which represented 137 percent of the $16.16 million of property cash flow generated by the core area. These 2004 exploration initiatives resulted in the drilling of 21.2 net wells that delivered 17.2 net natural gas wells and 4.0 net dry holes.

During 2004, the core area's production volumes increased 23 percent to 1,814 barrels of equivalent per day and the undeveloped acreage increased by seven percent to 185 thousand net acres, but the core area's proved and probable reserves showed a three percent decrease to 4.17 million barrels of equivalent. Following a very strong 2003 exploration program, Zargon's West Central Alberta's exploration program disappointed in 2004, delivering proved and probable reserve additions at a cost of $40.95 per barrel of equivalent and production additions at a cost of $34.3 thousand per barrel of equivalent per day.

Prior to 2004, the West Central Alberta core area capital programs had delivered reasonable finding and development costs and production addition costs, considering the large component of "up-front" capital that is required in the early stages of building a new exploration area. Unlike 2003, when the West Central Alberta drilling program delivered significant new reserves and production, the 2004 exploration program resulted in numerous completions for minor secondary zones, but no large discoveries were made.

Going forward, Zargon remains committed to its West Central Alberta exploration initiatives, but will reduce its capital program exposure to less than 75 percent of the core area's property cash flow. This adjustment will be accomplished by high-grading the existing drilling program and by bringing in financial partners on a promoted basis to help drill some of the higher risk but higher reward opportunities. Significant exploration opportunities exist in each of the following key properties:

WEST CENTRAL ALBERTA PRODUCTION (boe/d)

2004 ACTIVITIES

- Shot 33 kilometres of 2D seismic and 12 square kilometres of 3D sesmic.
- Drilled 20.6 net wells, resulting in 16.6 net gas wells and 4.0 net dry holes.
- Constructed six net kilometres of pipelines, and tied-in 3.4 net gas wells into existing gathering systems.
- Spent $22.12 million on capital projects, or 137 percent of the West Central Alberta core area's property cash flow.
- Increased West Central Alberta production by 23 percent to 1,814 barrels of equivalent per day.

2005 PLANS

- Continue to explore the West Central Alberta undeveloped land base, through the shooting of 2D seismic, the building of natural gas exploration projects and the drilling of natural gas exploration wells.
- Drill approximately 14 net wells at the Pembina, Peace River Arch and Greater Highvale areas.
- Reinvest less than 75 percent of the core area's property cash flow to grow production levels to 2,000 barrels of equivalent per day.

WEST CENTRAL ALBERTA

	2004	2003	2002	2001
Average Production				
Oil (bbl/d)	**218**	260	234	156
Natural gas (mmcf/d)	**9.56**	7.27	2.31	1.97
Equivalents (boe/d)	**1,814**	1,472	619	484
Total Proved & Probable Reserves (1)				
Oil (mbbl)	**499**	585	618	488
Natural gas (bcf)	**22.00**	22.19	18.56	11.61
Equivalents (mboe)	**4,166**	4,283	3,711	2,423
Undeveloped Lands				
Net acres (thousands)	**184.9**	173.6	109.1	38.4
Drilling Activities				
Net wells	**20.6**	17.8	12.8	4.1
Capital Expenditures ($ million)				
Net property acquisitions	**0.40**	(2.33)	5.25	0.48
Undeveloped land, seismic, geological	**4.77**	7.50	4.55	1.20
Drilling, completion, equipping, facilities	**16.95**	10.38	7.12	2.47
Total expenditures	**22.12**	15.55	16.92	4.15
Capital Program Efficiencies				
Finding, development and acquistion cost ($/boe) (2)	**40.95**	13.63	12.50	11.14
Production addition cost ($thousand/boe/d) (3)	**34.3**	16.1	74.8	48.3

1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The reported proved and probable finding, development and acquisition cost includes an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and changes in reserve definitions.*
3. *The production addition costs are calculated assuming trust average natural gas and oil annual decline rates of 23 percent and 10 percent, respectively. The calculations make the simplifying assumptions that all capital expenditures were made at the beginning of the year.*

GREATER HIGHVALE

The cornerstone of this property is a 54-section land block situated on and around the Paul First Nation lands located west of Edmonton. Zargon owns and operates natural gas production infrastructure in the area and pursues seismically defined structural prospects at medium depths. The structural geology lends itself to stacked pay with potential for multiple pay zones. Zargon's infrastructure ownership complements the Trust's 40 thousand net acres of undeveloped land in the Greater Highvale area.

Greater Highvale activities in 2004 included the shooting of a 12 square kilometre 3D seismic program and the drilling of 4.9 net wells that resulted in 2.9 net natural gas wells and 2.0 net dry holes. The Greater Highvale property provided 3.06 million cubic feet per day and 197 barrels per day of production to Zargon in 2004.

In 2005, Zargon plans to tie in 2.6 net wells from prior drilling programs to area facilities and plans to drill two net additional wells on seismically identified structural prospects.

PEMBINA SHALLOW GAS

Since 2000, Zargon has been pursuing the shallow low pressure Scollard and Horseshoe Canyon sands in the Pembina area at depths up to 900 metres. The project is characterized by multiple under-pressured gas sands that can provide initial gas rates of up to 0.75 million cubic feet per day.

In the last five years, Zargon has acquired an inventory of 52 thousand net acres of shallow natural gas prospective undeveloped land, drilled 29 net wells and constructed a sweet natural gas gathering and compression facility. In 2004, Zargon drilled 4.8 net gas wells in the Pembina area, and the property provided 2.40 million cubic feet per day of production to Zargon's interest.

Also in 2004, Zargon drilled 2.0 net gas wells and recompleted 2.0 net gas wells on an industry farm-in on the Blackfeet Indian reservation in northern Montana, United States. The prospect was initiated to attempt to prove up a potentially analogous areally extensive natural gas resource opportunity on a large unexplored block of land. Following a thorough evaluation of the exploration results, Zargon elected to not make further drilling commitments and Zargon's rights to earn additional interests were forfeited.

In 2005, Zargon is planning to tie in 3.1 net wells from prior drilling programs in Pembina to area facilities and plans on drilling eight net additional wells on recently identified higher permeability sand trends.

PEACE RIVER ARCH EXPLORATION

In the Peace River Arch exploration area, Zargon is pursuing multiple zone gas exploration prospects at drilling depths ranging from 300 to 1800 metres. The Peace River Arch exploration strategy is more "grassroots" than in other areas as the Trust develops prospects, posts land, shoots seismic and drills high-graded prospects. Over the last three years, Zargon has built an 82 thousand net acre undeveloped land inventory that is generally characterized by year round surface access and sweet natural gas multi-zone prospects.

In 2004, the Trust drilled 8.6 net wells in the Peace River Arch area that resulted in 6.6 net gas wells and 2.0 net abandonments. Based on 2003 drilling successes, the Peace River Arch area's production climbed sharply to reach a 2004 average natural gas rate of 4.10 million cubic feet per day with 24 barrels per day of oil and natural gas liquids.

In 2005, Zargon plans to tie in 3.0 net wells from prior drilling programs to area facilities and plans to drill four net additional wells on seismically identified prospects. Exploration in the area provides significant upside to Zargon, but also provides a significant amount of risk. Zargon plans to manage this risk in 2005 by high-grading its existing drilling program and by bringing in financial partners on a promoted basis to help drill some of the higher risk but higher reward opportunities.

In the Williston Basin Zargon holds a significant inventory of exploitable properties producing from Mississippian carbonate reservoirs characterized by shallow production declines and a large oil-in-place.

Williston Basin

The Williston Basin core area is characterized by a very stable oil production base that offers significant long-term exploitation opportunities. The core area provides substantial cash flows that can be allocated to trust distributions or can be reinvested to provide production growth.

The Williston Basin properties are located in relatively close proximity in Southeast Saskatchewan, Southwest Manitoba and in the northern part of the State of North Dakota. The properties produce light and medium gravity oil from carbonate reservoirs at depths up to 1,500 metres. The Williston Basin contributes 83 percent of the Trust's proved and probable oil reserves and provides a long proved and probable reserve life of 12.6 years.

Zargon's Williston Basin producing reservoirs are characterized by oil-wet, moderate permeability and as a rule a large remaining oil-in-place. By the nature of the physical characteristics of these oil-bearing reservoirs, the properties demonstrate stable production profiles with low percentage annual declines and consequently are associated with long reserve life indices.

Through exploitation projects, Zargon attempts to find methods to increase the ultimate oil recoveries from these reservoirs. Generally, Zargon uses a combination of exploitation techniques including pressure maintenance by water injections, 3D seismic and horizontal drilling to unlock additional oil reserves. Frequently, optimizing pressure support in the oil reservoir by water injections is the first step in the exploitation process. With pressure support established, Zargon seeks to characterize the reservoirs through 3D seismic analysis and interpretation, which is followed by the drilling of horizontal wells designed to increase recoveries and accelerate production.

The following table identifies twenty Williston Basin waterflood exploitation projects that Zargon is currently undertaking:

WILLISTON BASIN OIL EXPLOITATION PROJECTS

	Waterflood Projects	Zargon Working Interest (%)	WI[1] Oil-in-Place (mmbbl)	WI Cumulative Production (mmbbl)	WI Recovery To Date (percent)	WI[2] Remaining Reserves (mmbbl)	WI Ultimate Recovery (mmbbl)	Ultimate Recovery (percent)
North Dakota								
Haas	1	98	51.2	9.6	18.7	3.9	13.4	26.2
Truro/Mackobee	2	100	22.0	2.5	11.4	1.2	3.8	17.3
Manitoba								
Daly/Virden	2	100	27.6	3.0	10.9	1.0	4.0	14.5
Saskatchewan								
Elswick	3	97	11.1	1.2	10.8	0.6	1.8	16.2
Frys	2	100	11.2	1.0	8.9	0.6	1.6	14.3
Midale	1	93	7.4	1.0	13.5	0.2	1.2	16.2
Pinto	2	100	4.6	0.3	6.5	0.2	0.6	13.0
Steelman	2	89	10.5	1.4	13.3	0.7	2.1	20.0
Weyburn North	3	75	19.7	2.7	13.7	0.9	3.6	18.3
Workman/Carnduff	2	55	8.6	1.3	15.1	0.4	1.7	19.8
Total	20		173.9	24.0	13.8	9.7	33.7	19.4

1. As estimated by Zargon Energy Trust.

2. Represents remaining proved and probable reserves as estimated by McDaniel & Associates.

These twenty projects, which represent 83 percent of Zargon's Williston Basin reserves, are in various stages of implementation and are estimated to contain almost 174 million barrels of oil-in-place attributed to Zargon's working interest. Based on the McDaniel proved and probable reserve assignments, the reservoirs in these properties are predicted to recover an average of only 19.4 percent of their original oil-in-place. Zargon will attempt to improve these ultimate recovery factors through a multi-year program of exploitation projects.

In 2004, Zargon drilled 5.0 net vertical and 2.5 net horizontal wells in the Williston Basin, resulting in 5.7 net oil wells and 0.8 net water injectors. The Trust also shot two 3D seismic programs at Truro, North Dakota and Steelman, Saskatchewan. In 2005, Zargon plans to implement a substantially larger capital program on this large Williston Basin opportunity base.

- Acquired various Weyburn, Saskatchewan producing oil properties with more than 250 barrels per day of stable production and exploitation potential.
- Shot 26 square kilometres of 3D seismic.
- Initiated new or enhanced waterfloods on four properties.
- Drilled 7.5 net wells resulting in 5.7 net oil wells, 0.8 net water injectors and one net dry hole.
- Excluding property acquisitions, spent $8.76 million on capital projects, or 35 percent of the Williston Basin core area's property cash flow.
- Increased Williston Basin production by eight percent to 2,643 barrels of equivalent per day.

- Continue the exploitation and development of the large Williston Basin resource base by shooting 3D seismic, implementing or modifying waterflood projects and by drilling wells.
- Drill a minimum of 11 net wells at the Elswick, Pinto, Steelman and Weyburn, Saskatchewan properties and the Haas and Truro, North Dakota properties.
- Reinvest approximately 50 percent of the core area's cash flow to grow this stable production base to 2,750 barrels of equivalent per day.
- Seek to acquire additional Williston Basin oil properties with significant exploitation potential.

In July, the Trust closed a $10-million property acquisition whereby the Trust acquired approximately 250 barrels per day from operated interests in the Weyburn and Elswick areas of Southeast Saskatchewan. This acquisition was highly complementary to Zargon as it provided operated control in six Units where Zargon already had adjacent or non-operated interests.

In 2004, the Williston Basin area generated $24.77 million of property cash flow of which, excluding acquisitions, $8.76 million or 35 percent was reinvested in the core area to maintain stable production volumes. Including $10.82 million of acquisitions, the Williston Basin capital program totalled $19.58 million and delivered an eight percent increase in the year-end proved and probable reserves to 12.09 million barrels of equivalent. The core area's production volumes also climbed eight percent in the year to 2,643 barrels of equivalent per day. The Williston Basin capital programs were very efficient in 2004, providing proved and probable reserve additions at $11.76 per barrel of equivalent. Reflecting only a half-year of new acquisition volumes, the cost of the new production additions was $42.7 thousand per barrels of equivalent per day. Adjusted for the effective date of the aquisition, the 2004 cost to add new Williston Basin production was approximately $31.6 thousand per barrels of equivalent.

Going forward, Zargon has identified numerous exploitation opportunities that should provide stable production volumes for many years to come with the reinvestment of less than 50 percent of the area's cash flow. Production growth can be anticipated from this core area if additional capital is allocated to these exploitation projects.

WILLISTON BASIN

	2004	2003	2002	2001
Average Production				
Oil (bbl/d)	**2,603**	2,387	2,074	1,569
Natural gas (mmcf/d)	**0.26**	0.37	0.46	0.25
Equivalents (boe/d)	**2,643**	2,449	2,151	1,611
Total Proved & Probable Reserves [1]				
Oil (mbbl)	**11,930**	11,105	9,761	9,336
Natural gas (bcf)	**0.98**	0.86	0.93	0.99
Equivalents (mboe)	**12,093**	11,248	9,916	9,501
Undeveloped Lands				
Net acres (thousands)	**45.1**	39.4	32.9	28.6
Drilling Activities				
Net wells	**7.5**	8.0	3.9	3.1
Capital Expenditures ($ million)				
Net property acquisitions	**10.82**	6.10	1.20	28.41
Undeveloped land, seismic, geological	**1.24**	2.13	0.90	1.49
Drilling, completion, equipping, facilities	**7.52**	6.86	4.17	2.98
Total expenditures	**19.58**	15.09	6.27	32.88
Capital Program Efficiencies				
Finding, development and acquisition cost ($/boe) [2]	**11.76**	6.66	5.21	6.32
Production addition cost ($thousand/boe/d) [3]	**42.7**	27.8	8.3	45.3

1. Proved and probable reserves are trust working interest reserves before royalties (6:1).

2. The reported proved and probable finding, development and acquisition cost includes an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year revisions and changes in reserve definitions.

3. The production addition costs are calculated assuming trust average natural gas and oil annual decline rates of 23 percent and 10 percent, respectively. The calculations make the simplifying assumptions that all capital expenditures were made at the beginning of the year.

WILLISTON BASIN PRODUCTION (boe/d)

HIGHLIGHTS

Zargon had an active and successful year in 2004, drilling 49.5 net wells, a 28 percent increase over the prior year. The record drilling program delivered a 10 percent gain in production, with natural gas production volumes climbing 16 percent, and oil and liquids production volumes increasing four percent. Year-end proved and probable natural gas and oil and natural gas liquids reserves increased four and six percent, respectively.

	2004	2003	Percent Change
Undeveloped land (thousand net acres)	**376**	398	(6)
Wells drilled, net	**49.5**	38.6	28
Natural gas production (mmcf/d)	**28.84**	24.95	16
Oil and liquids production (bbl/d)	**3,416**	3,287	4
Year-end proved and probable natural gas reserves (bcf)	**69.56**	67.07	4
Year-end proved and probable oil reserves (mmbbl)	**14.36**	13.56	6

LAND AND SEISMIC

In 2004, Zargon spent $3.84 million on replenishing and maintaining its undeveloped land base. This total was 45 percent lower than the $6.98 million spent in 2003 when land costs were substantially lower. During the year, Zargon purchased 39 thousand acres of generally natural gas prospective Alberta Crown lands for a total cost of $3.63 million or $93 per acre. Previously, Zargon had acquired 77 thousand net acres in 2003 and 73 thousand net acres in 2002 at average costs of $81 and $58 per acre, respectively. Zargon's higher land costs reflect industry trends to higher Alberta Crown land costs of $145 per acre in 2004, a 26 percent increase over the prior year.

Zargon's undeveloped land inventory decreased six percent in 2004, to 376 thousand net acres. This decline resulted from the combination of a reduced land acquisition capital program and an unusually large inventory of 2004 expiries. While Zargon will continue to make purchases at Crown sales, another small decrease in the undeveloped land inventories is anticipated in 2005 because of expiries.

The independent firm Seaton-Jordan & Associates Ltd. ("Seaton-Jordan") has valued Zargon's undeveloped land holdings as of December 31, 2004 at $32.20 million, an 11 percent increase in value over last year's $28.95 million appraisal. This analysis reflects an average value of $86 per acre that compares with the $73 per acre average in 2003.

As part of its continuing exploration effort, Zargon shot 235 kilometres of 2D seismic and 42 square kilometres of 3D seismic in 2004. Approximately, 200 kilometres of the 2D seismic were shot at the Jarrow property as Zargon continued to assess its considerable inventory of land and natural gas prospect leads in this productive area. Total geological and geophysical costs in 2004 were $5.26 million, which is almost unchanged from last year's geological and geophysical expenditures of $5.69 million.

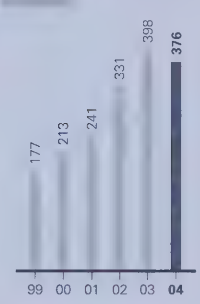
DRILLING, COMPLETIONS AND WORKOVERS

Zargon drilled a total of 49.5 net wells in 2004, a 28 percent increase in drilling activity from 2003 and a 57 percent increase from 2002. The 2004 drilling program resulted in 5.7 net oil wells, 35.4 net gas wells, 0.8 net water injectors and 7.6 net dry holes. Zargon's success ratio was 85 percent in the 2004 drilling program, in line with the 84 percent success in 2003.

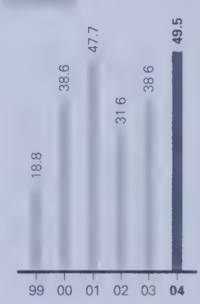
DRILLING ACTIVITY

Number of Wells	Gross	2004 Net	Gross	2003 Net	Gross	2002 Net
Oil	**7**	**5.7**	11	8.0	7	6.9
Natural Gas	**44**	**35.4**	35	24.6	24	20.7
Water Injector	**1**	**0.8**	–	–	–	–
Dry	**8**	**7.6**	6	6.0	4	4.0
Total	**60**	**49.5**	52	38.6	35	31.6
Exploratory	**29**	**25.9**	35	29.4	26	23.0
Development	**31**	**23.6**	17	9.2	9	8.6
Total	**60**	**49.5**	52	38.6	35	31.6
West Central Alberta	**23**	**20.6**	23	17.8	14	12.8
Alberta Plains	**28**	**21.4**	20	12.8	17	14.9
Williston Basin	**9**	**7.5**	9	8.0	4	3.9
Total	**60**	**49.5**	52	38.6	35	31.6
Average Zargon Working Interest		**83%**		74%		90%

UNDEVELOPED LAND
(thousand net acres)



DRILLING ACTIVITY
(net wells)



During 2004, Zargon operated the drilling of 51 gross wells with an average working interest of 91 percent. Zargon's minor participation in an additional nine non-operated wells brought Zargon's average working interest to 83 percent. Similar to recent years, the drilling program was heavily weighted to Alberta natural gas targets with 85 percent of the wells drilled in the Alberta Plains and West Central Alberta natural gas properties. In 2005, Zargon is planning to drill 45 net wells emphasizing natural gas exploration and development in the Alberta Plains and West Central Alberta, but with an increased emphasis on oil exploitation in the Williston Basin.

In 2004, expenditures for drilling, completion and workovers totalled $26.94 million, a 56 percent increase from the $17.30 million spent in 2003. Drilling related expenditures were sharply higher, due specifically to Zargon's increased activity levels in the deeper and more expensive West Central Alberta core area and due in general to an industry-wide trend to higher costs.

PRODUCTION EQUIPMENT AND FACILITIES

In 2004, Zargon spent $8.42 million on production equipment and facilities, which included gas plant expansions, oil battery modifications and the construction of approximately 33 net kilometres of pipelines. These costs were approximately equally divided between the Alberta Plains, West Central Alberta and Williston Basin core areas and represented in total a 15 percent increase over the prior year's levels.

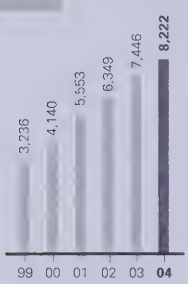
PROPERTY ACQUISITIONS

Zargon's net property acquisitions of $11.81 million in 2004 were sharply higher than the $2.61 million of net property acquisitions completed in 2003. Essentially all of the 2004 acquisitions related to the purchase of a portfolio of oil properties in the Weyburn and Elswick, Saskatchewan areas of the Williston Basin.

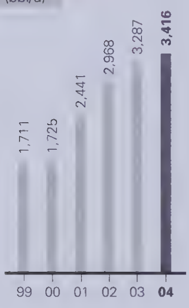
PRODUCTION

Natural gas sales volumes increased 16 percent in 2004 to average 28.84 million cubic feet per day, compared to 24.95 million cubic feet per day in 2003 (2002 – 20.29 mmcf/d). Increases in natural gas production came from each of the three West Central Alberta major properties of Highvale, Pembina and Peace River Arch and from Jarrow in the Alberta Plains. Crude oil and natural gas liquid sales volumes increased four percent in 2004 to 3,416 barrels per day, compared to 3,287 barrels per day in 2003 (2002 – 2,968 bbl/d). These production gains resulted from the oil exploitation drilling program and the acquisition of properties in the Williston Basin.

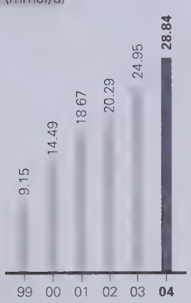
PRODUCTION
(boe/d)



OIL AND LIQUID PRODUCTION
(bbl/d)



NATURAL GAS PRODUCTION
(mmcf/d)



Zargon's 2004 average daily production climbed 10 percent, to 8,222 barrels of equivalent per day compared to 7,446 barrels of equivalent per day in 2003 (2002 – 6,349 boe/d). On a production per total trust unit basis, Zargon produced 447 barrels of equivalent per day per million units in 2004, a seven percent gain over the 2003 levels. During the year natural gas production represented 58 percent of total volumes, up slightly from a 56 percent weighting in 2002.

RESERVES

Formal disclosure of oil and natural gas reserves as required by National Instrument 51-101 Standards of Disclosure ("NI 51-101") will be included in the Trust's Renewal Annual Information Form for the year ended December 31, 2004 that will be filed on SEDAR.

Since 1993, the independent engineering firm of McDaniel & Associates Consultants Ltd. ("McDaniel") has evaluated 100 percent of Zargon's reserves. Commencing with the 2003 year-end report, Zargon's reserve estimates have been calculated in accordance with NI 51-101. Under NI 51-101, proved reserve estimates are defined as having a 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. Probable reserves are defined under NI 51-101 so that there are equal (50 percent) probabilities that the actual reserves to be recovered will be less than, or greater than, the proved and probable reserves estimate.

In a report dated March 3, 2005, McDaniel assigned the following reserve estimates based on forecast prices and costs as of December 31, 2004:

TRUST RESERVES [1]

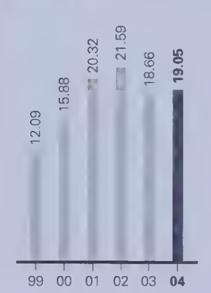
At December 31, 2004	Oil and Liquids (mmbbl)	Natural Gas (bcf)	Equivalents [2] (mmboe)
Proved producing	10.76	37.32	16.98
Proved non-producing	0.08	10.80	1.88
Proved undeveloped	0.11	0.45	0.19
Total proved	**10.95**	**48.57**	**19.05**
Probable additional	3.41	20.99	6.90
Total proved and probable	**14.36**	**69.56**	**25.95**
Proved reserve life index, years	8.3	4.6	6.2
Proved and probable reserve life index, years	10.9	6.6	8.4

1. *Trust working interest reserves before royalties, boe (6:1).*
2. *Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

In McDaniel's report, proved producing reserves represented 89 percent of Zargon's total proved reserves while total proved reserves accounted for 73 percent of proved plus probable reserves. These percentages are substantially unchanged from the respective 90 and 76 percentages reported in the 2003 year-end report. Zargon's proved non-producing reserves are comprised primarily of natural gas reserves from recently drilled wells at the West Central Alberta Pembina, Greater Highvale and the Peace River Arch properties and behind pipe natural gas reserves at the Alberta Plains Jarrow and Hamilton Lake properties. Proved undeveloped reserves represent only one percent of the total proved reserves. McDaniel forecasts $6.41 million of net future (forecast prices) capital costs to deliver the total proved reserve estimate. Zargon's probable reserves generally reflect incremental waterflood recoveries on producing oil properties and improved gas recoveries for currently producing natural gas wells. McDaniel forecasts $8.37 million of net future (forecast prices) capital costs to deliver the total proved and probable reserve estimate.

Based on 2004 year-end reserves and Zargon's 2004 fourth-quarter production rates of 3,618 barrels of oil per day and 28.93 million cubic feet of natural gas per day, Zargon's proved reserve life index is 8.3 years for oil, 4.6 years for natural gas and 6.2 years on an equivalent basis. The corresponding proved and probable oil, natural gas and equivalent reserve life indices are 10.9, 6.6 and 8.4 years, respectively. The relatively high oil reserve life reflects Zargon's portfolio of long-life shallow-decline Williston Basin waterflood projects.

PROVED RESERVES
(mmboe)



RESERVE RECONCILIATION

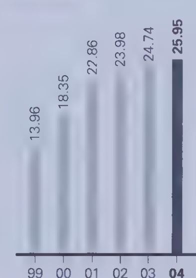
A reconciliation of the 2004 year-end reserve assignments with the reserves reported in the 2003 year-end report is presented below.

RESERVE RECONCILIATION

	Oil and Liquids (mmbbl)			Natural Gas (bcf)			Equivalents (mmboe)		
	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.
December 31, 2003 [1]	10.50	3.06	13.56	48.95	18.12	67.07	18.66	6.08	24.74
Discoveries & extensions	0.36	0.24	0.60	8.96	5.33	14.29	1.85	1.12	2.97
Revisions	0.57	(0.12)	0.45	1.48	(2.40)	(0.92)	0.82	(0.52)	0.30
Acquisitions & dispositions	0.77	0.23	1.00	(0.27)	(0.06)	(0.33)	0.73	0.22	0.95
Production	(1.25)	–	(1.25)	(10.55)	–	(10.55)	(3.01)	–	(3.01)
December 31, 2004	10.95	3.41	14.36	48.57	20.99	69.56	19.05	6.90	25.95

1. *Certain comparative numbers reflect the retroactive restatement of removing royalty interest reserves from the Trust interest reserves in accordance with NI 51-101.*

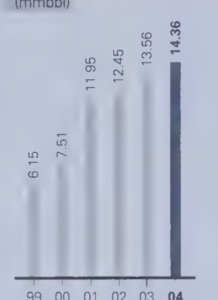
PROVED AND
PROBABLE RESERVES
(mmboe)



Proved reserves at December 31, 2004 increased two percent from the prior year. Proved 2004 reserve additions were 3.40 million barrels of equivalent (after revisions) or 2.58 million barrels of equivalent (before revisions). Positive technical reserve revisions were 0.82 million barrels of equivalent, which equated to four percent of the 2004 proved reserves' opening balance. The majority of the positive revisions were attributed to performance-related adjustments to waterflood oil properties in the Williston Basin.

On a proved and probable basis, Zargon increased its reserves by five percent in 2004, with the addition of 4.22 million barrels of equivalent (after revisions) or 3.92 million barrels of equivalent (before revisions), thereby replacing annual production by a factor of 140 percent (130 percent before revisions). Field capital exploration and development programs provided 2.97 million barrels of equivalent of new additions, while net acquisitions, primarily in Southeast Saskatchewan, added 0.95 million barrels of equivalent. Postive technical reserve revisions were 0.30 million barrels of equivalent which equated to one percent of the 2004 proved and probable reserves opening balance. The 2004 reserve additions were derived from a $56.27 million net capital expenditure program. Included in the 2004 capital expenditure program was $9.10 million of undeveloped land and seismic costs that should provide for future reserves additions in subsequent years.

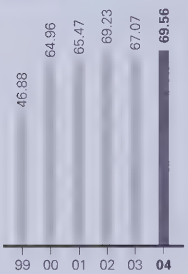
PROVED AND PROBABLE
OIL AND LIQUID RESERVES
(mmbbl)



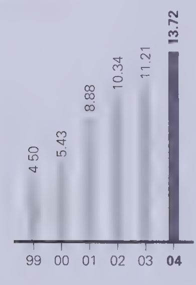
FINDING, DEVELOPMENT AND ACQUISTION COSTS

For 2004, Zargon's proved and probable finding, development and acquisition costs ("FD&A costs"), taking into account reserve revisions and changes in estimated future development capital during the period, were $13.72 per barrel of equivalent. For the purposes of this calculation, the $56.27 million of 2004 net capital additions were combined with an increase in estimated future development capital for proved and probable reserves of $1.61 million ($8.37 million at December 31, 2004 compared to $6.76 million at December 31, 2003). If future development costs are excluded, the 2004 proved and probable finding, development and acquisition costs, taking into account reserve revisions, were $13.33 per barrel of equivalent.

PROVED AND PROBABLE NATURAL GAS RESERVES
(bcf)



PROVED AND PROBABLE FINDING, DEVELOPMENT AND ACQUISITION COSTS
($/boe)



PROVED AND PROBABLE FINDING, DEVELOPMENT AND ACQUISITION COSTS [1]

	2004	2003	2002	2001	2000	1999
Total net capital expenditures ($ million)	**56.27**	39.91	35.55	55.18	30.51	16.95
Total net capital expenditures plus change in forecast future development costs ($ million)	**57.88**	39.00	35.57	58.06	32.05	18.09
Proved and probable reserves (mmboe) [2]						
Open	**24.74**	23.98	22.86	18.35	13.96	11.12
Additions (discoveries, extensions, net acquisitions)	**3.92**	4.48	4.68	6.95	5.27	3.52
Revisions	**0.30**	(1.00)	(1.24)	(0.41)	0.63	0.50
Production	**(3.01)**	(2.72)	(2.32)	(2.03)	(1.51)	(1.18)
Close	**25.95**	24.74	23.98	22.86	18.35	13.96
Proved and probable FD&A costs ($/boe) [2]	**13.72**	11.21	10.34	8.88	5.43	4.50
Proved and probable three-year FD&A cost ($/boe) [2]	**11.89**	9.85	7.91	6.57	na	na

1. *In this table, the established reserves (proved plus 50 percent probable) for the prior years (1999-2002) are used as a comparison to the December 31, 2003 and 2004 proved and probable reserves, so as to reflect the difference in the risk applied to these reserves as a result of the NI 51-101 guidelines.*
2. *Certain comparative numbers reflect the retroactive restatement of removing royalty interest reserves from Trust interest reserves in accordance with NI 51-101.*

Zargon experienced higher FD&A costs in 2004. The industry-wide trend to higher costs, as well as weaker than expected drilling results in the West Central Alberta area, were key contributors to the increase in FD&A costs.

TRUST PERFORMANCE

	2004	2003	2002	2001	2000	1999	Three Year Average (2002-2004)	Six Year Average (1999-2004)
Trust cash flow ($/boe) [2]	**21.18**	20.00	13.86	16.12	18.15	9.01	18.67	17.31
Proved and probable FD&A costs ($/boe) [1] [4]	**13.72**	11.21	10.34	8.88	5.43	4.50	11.89	8.72
Trust recycle ratio [3] [4]	**1.5**	1.8	1.3	1.8	3.3	2.0	1.6	2.0
Production addition cost ($thousand/boe/d) [5]	**27.8**	18.4	20.2	25.8	21.4	15.9	22.2	22.2

1. *Finding, development and acquisition costs taking into account reserve revisions and changes in estimated future development capital during the period on a barrel of oil equivalent basis (6:1).*
2. *Trust cash flow from operations including allowances for current taxes, interest charges and general and administrative costs on a barrel of oil equivalent production basis (6:1).*
3. *Trust recycle ratio is defined as the trust cash flow per barrel of equivalent divided by proved and probable finding, development and acquisition costs.*
4. *Certain comparative numbers reflect the retroactive restatement of removing royalty interest reserves from gross trust interest reserves in accordance with NI 51-101.*
5. *The production addition costs are calculated assuming trust average natural gas and oil annual decline rates of 23 percent and 10 percent, respectively. The calculations make the simplifying assumptions that all capital expenditures were made at the beginning of the year.*

NET ASSET VALUE

Zargon's oil, natural gas liquids and natural gas reserves were evaluated using McDaniel product price forecasts effective January 1, 2005, prior to provisions for income taxes, interest, debt service charges and general and administrative expenses. It should not be assumed that the following discounted future net property cash flows estimated by McDaniel represent the fair market value of the reserves:

BEFORE TAX PRESENT VALUE OF FUTURE NET REVENUE (FORECAST PRICE CASE)

($ million)	Discount Factor 0%	5%	10%	15%
Proved producing	276.8	237.9	208.5	186.2
Proved non-producing	38.2	33.4	29.6	26.6
Proved undeveloped	2.5	1.8	1.3	0.9
Total proved	**317.5**	**273.1**	**239.4**	**213.7**
Probable	132.4	92.2	68.8	54.1
Total proved and probable	**449.9**	**365.3**	**308.2**	**267.8**

BEFORE TAX PRESENT VALUE OF FUTURE NET REVENUE (CONSTANT PRICE CASE)

($ million)	Discount Factor 0%	5%	10%	15%
Proved producing	314.4	259.1	221.5	194.5
Proved non-producing	43.5	37.7	33.1	29.5
Proved undeveloped	3.0	2.1	1.5	1.1
Total proved	**360.9**	**298.9**	**256.1**	**225.1**
Probable	148.2	101.3	75.0	58.6
Total proved and probable	**509.1**	**400.2**	**331.1**	**283.7**

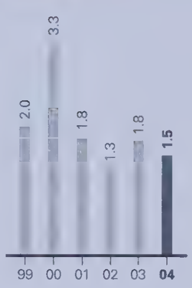
The above discounted future net property cash flows are based on the McDaniel forecast and constant price assumptions that are contained in the following table:

MCDANIEL REPORT PRICING ASSUMPTIONS (FORECAST AND CONSTANT PRICE CASES)

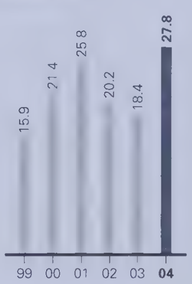
	WTI Crude Oil ($US/bbl)	Edm. Par Price ($Cdn/bbl)	Cromer Med. ($Cdn/bbl)	AECO Gas Price ($Cdn/gj)	Exchange Rate ($US/$Cdn)	Inflation Rate (%)
Forecast Prices						
2005	42.00	49.60	43.50	6.45	0.83	2.0
2006	39.50	46.60	40.90	6.20	0.83	2.0
2007	37.00	43.50	38.20	6.05	0.83	2.0
2008	35.00	41.10	36.00	5.80	0.83	2.0
2009	34.50	40.50	35.50	5.70	0.83	2.0
2010	34.30	40.20	35.30	5.60	0.83	2.0
Thereafter:	Escalate at 2%/year	Escalate at 2%/year	Escalate at 2%/year	Escalate at 2%/year	0.83	2.0
Constant Prices						
2004 year-end	43.45	46.51	38.46	6.62	0.83	–

The following net asset value table shows what is customarily referred to as a "produce-out" net asset value calculation under which the current value of Zargon's reserves would be produced at McDaniel forecast future prices and costs. The value is a snapshot in time as of December 31, 2004 and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. In this analysis, the present value of the proved and probable reserves is calculated at a before tax 10 percent discount rate, and the value assigned to the undeveloped land was provided by the independent firm of Seaton-Jordan and Associates Ltd.

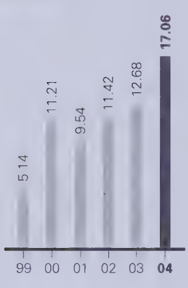
PROVED AND PROBABLE TRUST RECYCLE RATIOS



PRODUCTION ADDITION COSTS
($ thousand/boe/d)



NET ASSET VALUE
(PVBT 10%)
($/diluted unit)



NET ASSET VALUE

As at December 31 ($ million)	2004	2003	2002	2001	2000	1999
Proved and probable reserves (PVBT 10%) [1] [2]	**308.2**	219.6	215.4	175.5	175.0	82.3
Undeveloped land [3]	**32.2**	29.0	22.4	18.5	14.9	9.8
Working capital	**(9.1)**	(6.1)	(3.5)	(3.5)	(2.5)	(0.1)
Bank debt	**(14.2)**	(7.0)	(25.3)	(24.1)	(15.9)	(14.1)
Proceeds from the exercise of all trust unit rights	**10.3**	9.1	6.2	4.0	3.5	3.6
Net asset value (including trust unit rights dilution)	**327.4**	244.6	215.2	170.4	175.0	81.5
Net asset value per unit						
Total ($/unit)	**17.04**	13.09	11.85	9.98	11.98	5.40
With full dilution ($/unit)[4]	**17.06**	12.68	11.42	9.54	11.21	5.14

1. *McDaniel's estimate of future before tax cash flow discounted at PV 10 percent. Reserves for December 31, 2002 and prior years are presented as established (proved plus 50 percent probable) reserves as the best comparison to December 31, 2003 and 2004 proved and probable reserves, reflecting the difference in the risk applied to these reserves as a result of the NI 51-101 guidelines.*
2. *PVBT represents present value before taxes.*
3. *Seaton-Jordan year-end estimates.*
4. *Full dilution of units represent the year-end units outstanding plus the presumed exercise of all trust unit rights and the conversion of exchangeable shares converted at the exchange ratio at the end of the period.*

If the net asset value calculation is adjusted to assume that the commodity prices received at year-end 2004 (Edmonton light crude oil at $46.51 Cdn per barrel and Alberta AECO natural gas at $6.62 Cdn per gj) will remain constant throughout the future (McDaniel constant price case), the equivalent analysis calculates a 10 percent present value before tax (PVBT) net asset value of $18.25 per fully diluted unit.

TRUST SUSTAINABILITY

With the conversion during 2004 to a trust, Zargon's objectives are to sustain distributions, production and reserves on a per unit basis after paying out approximately 50 percent of cash flow attributable to unitholders. The following is a summary of the key metrics that Zargon monitors as it works towards meeting its sustainability objectives:

KEY SUSTAINABILITY METRICS

	2004	2003	Percent Change
Annualized cash distributions ($/unit)	**1.68**	–	na
Cash flow from operations ($/unit diluted)	**3.40**	2.96	15
Trust payout ratio (percent)	**49**	–	na
Production (boe/d per million total units)	**447**	418	7
Proved and probable reserves (boe/total unit) [1]	**1.39**	1.38	1
Cash flow from operations ($/boe)	**21.18**	20.00	6
Proved and probable FD&A costs ($/boe)	**13.72**	11.21	22
Trust recycle ratio	**1.54**	1.78	(13)
Production addition costs ($ thousand/boe/d) [2]	**27.8**	18.4	51

1. *Certain comparative numbers reflect the retroactive restatement of removing royalty interest reserves from Trust interest reserves in accordance with NI 51-101.*
2. *The production addition costs are calculated assuming trust average natural gas and oil annual decline rates of 23 percent and 10 percent, respectively. The calculations make the simplifying assumptions that all capital expenditures were made at the beginning of the year.*

Management's discussion and analysis (MD&A) is a review of Zargon Energy Trust's 2004 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2004 and 2003. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. All references to "Zargon" or the "Trust" refer to Zargon Energy Trust and all references to the "Company" refer to Zargon Oil & Gas Ltd.

In the MD&A, reserves and production are commonly stated in barrels of equivalent (boe) on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil (boe). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalent at the wellhead.

Non-GAAP Measurements: The MD&A contains the term "cash flow from operations" ("cash flow"), which should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Trust's financial performance. This term does not have any standardized meaning as prescribed by GAAP and therefore, the Trust's determination of cash flow from operations may not be comparable to that reported by other trusts. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the consolidated financial statements. The Trust evaluates its performance based on net earnings and cash flow from operations. The Trust considers cash flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investment. It is also used by research analysts to value and compare oil and gas trusts, and it is frequently included in published research when providing investment recommendations. Cash flow from operations per unit is calculated using the diluted weighted average number of units for the period.

Forward-Looking Statements: This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this MD&A are as of March 14, 2005 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

This MD&A has been prepared as of March 14, 2005.

Plan of Arrangement

On July 15, 2004, approval was given by the shareholders to a resolution in favour of a Plan of Arrangement (the "Arrangement") reorganizing Zargon Oil & Gas Ltd. (the "Company") into Zargon Energy Trust (the "Trust" or "Zargon"). The Arrangement received court approval and also became effective on July 15, 2004. The Arrangement resulted in shareholders of the Company receiving either one trust unit or one exchangeable share for each common share held. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive distributions but rather on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The exchangeable shares are traded on the Toronto Stock Exchange and can be converted, at the option of the holder, into trust units at any time. On July 15, 2014, all the remaining outstanding exchangeable shares will be redeemed into trust units unless the Board of Directors of the Company elect to extend the redemption period. In certain circumstances, the Company has the right to require redemption of the exchangeable shares prior to July 15, 2014. Upon completion of the Arrangement, 14.87 million trust units and 3.66 million exchangeable shares were issued. The Trust is an unincorporated open-end investment trust governed by the laws of the Province of Alberta. It is the intent of the Trust to distribute approximately 50 percent of the cash flow from operations attributable to outstanding unitholders.

The reorganization of the Company into a Trust has been accounted for using the continuity of interest method. Accordingly, the consolidated financial statements for the year ended December 31, 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business of the Company. All comparative figures referred to in the consolidated financial statements and this MD&A are the previous consolidated results of the Company.

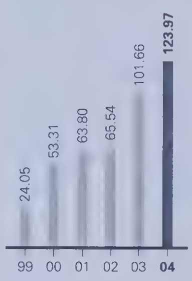
Monthly distributions of $0.14 per unit from the Trust commenced in August 2004, with a 2004 total of $10.70 million ($0.70 per unit) declared distributable to unitholders. This monthly distribution matches what was estimated at the time of the Arrangement. These distributions are a return on capital and are 100 percent taxable income to unitholders.

2004 Highlights

The combination of high crude oil prices, continued strong natural gas prices and production volume gains enabled Zargon to achieve record revenues and cash flow from operations in 2004, showing gains of 22 percent and 17 percent, respectively, over the prior year. The annual revenue gain came from a combination of factors, including a 24 percent increase in oil and liquids prices, a four percent increase in oil and liquids production and a 16 percent gain in natural gas production. The percentage increase in cash flow from operations was not as high as the increase in revenues due to increased royalties and operating costs. Net earnings for the year were $20.63 million, a 15 percent reduction from 2003. Earnings for 2003 were enhanced significantly by the mid-year announcement of future federal tax rate reductions that produced a large one-time reduction in future tax provisions. Earnings for 2004 were impacted by a significant one-time charge of $2.17 million related to the accelerated vesting of stock options as a result of the July 15, 2004 Arrangement and also an increase in depletion and depreciation of $7.75 million related to increased production volumes and upward pressure on finding and development costs in the industry. Also, a charge of $1.87 million for non-controlling interest related to the exchangeable shares was incurred due to the adoption of the CICA Emerging Issues Committee accounting standard EIC-151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts".

Net capital expenditures for 2004 totalled $56.27 million with $44.46 million allocated to field-related activities. The 2004 capital program showed a 41 percent increase in overall net expenditures and a 19 percent increase in field-related expenditures. Net property acquisitions increased by $9.20 million, primarily due to the acquisition of a portfolio of oil properties in Weyburn and Elswick, Saskatchewan of the Williston Basin. This acquisition occurred on July 26, 2004 and added approximately 250 barrels per day of oil production. For the year ended December 31, 2004, Zargon spent $3.84 million to maintain an undeveloped land base of 376,000 net acres (2003 – 398,000 net acres); shot or acquired seismic at a cost of $5.26 million; drilled, equipped and tied-in wells for $35.36 million and made net property acquisitions of $11.81 million. Also, costs incurred to reorganize into a trust were $9.44 million (of which $7.87 million relates to the settlement of employee and director stock options as part of the Arrangement) and distributions to unitholders totalled $10.70 million during the year. All of these activities were funded by the high cash flows received throughout the year plus an increase in debt net of working capital of $10.27 million.

PETROLEUM AND NATURAL GAS REVENUE
($ million)



FINANCIAL HIGHLIGHTS

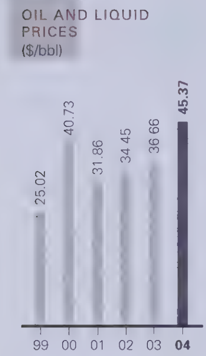
($ million, except per unit amounts)	2004	2003	2002
Petroleum and natural gas revenue	**123.97**	101.66	65.54
Cash flow from operations	**63.75**	54.35	32.12
Per unit – diluted	**3.40**	2.96	1.81
Net earnings [1]	**20.63**	24.36	10.70
Per unit – diluted [1]	**1.20**	1.33	0.60
Total assets [1]	**226.96**	181.05	160.01
Net capital expenditures	**56.27**	39.91	35.55
Bank indebtedness	**14.23**	6.98	25.28
Cash distributions	**10.70**	–	–

1. Comparative period numbers reflect the retroactive restatements due to a change in accounting policy.

Detailed Financial Analysis

PETROLEUM AND NATURAL GAS REVENUE

Zargon derives its revenue from the production and sale of petroleum (oil, natural gas liquids) and natural gas. Petroleum and natural gas revenue, exclusive of hedges, increased 22 percent to $123.97 million in 2004 from $101.66 million in 2003 due to increased production and higher prices. Because of the gains in both oil production volumes and prices received, the allocation of production revenue in 2004 increased to 46 percent from the sale of oil and liquids and 54 percent from the sale of natural gas, compared to 43 percent from oil and liquids and 57 percent from natural gas in the preceding year. Production volumes in 2004 increased 10 percent from the prior year, made up of a natural gas production increase of 16 percent and an oil and liquids production increase of four percent. Production increases for natural gas resulted primarily from the drilling and tie-in of new wells in the West Central Alberta and the Alberta Plains core areas. Production increases in oil and liquids resulted from Williston Basin property acqusitions and field exploitation programs. The average price of oil and liquids received by Zargon rose to $45.37 per barrel in 2004, up 24 percent from 2003. The average field price of natural gas was $6.37 per thousand cubic feet in 2004, a one percent increase over $6.33 per thousand cubic feet in 2003.



PETROLEUM (OIL AND NATURAL GAS LIQUIDS) PRICING

Zargon's field oil and natural gas liquids prices are adjusted at the point of sale for transportation charges and oil quality differentials from an Edmonton light sweet crude price that varies with world commodity prices. In 2004, Zargon's average oil and liquids field price, exclusive of price hedges, rose 24 percent to $45.37 per barrel from $36.66 per barrel in 2003 and $34.45 per barrel in 2002. The field price differential for Zargon's average blended 30 degree API crude stream was $7.17 per barrel less than the 2004 Edmonton reference crude price, which compares to the 2003 differential of $6.48 per barrel and the 2002 differential of $5.49 per barrel. As the quality and weight of Zargon's crude stream have remained relatively consistent for several years, the movements in the Zargon's price differential is derived from the North American refinery supply and demand factors for light and medium crudes.

NATURAL GAS PRICING

The average field natural gas price exclusive of price hedges for 2004 remained strong at $6.37 per thousand cubic feet which is relatively unchanged from the 2003 average of $6.33 per thousand cubic feet. The average for 2003 was 66 percent above 2002, 22 percent above both 2001 and 2000 and far above all previous years.

Approximately 23 percent of Zargon's 2004 natural gas production was sold under aggregator contracts pursuant to long-term contracts with Cargill Gas Marketing Ltd. (Jarrow - 18 percent) and ProGas Limited (Hamilton Lake - five percent), compared to 35 percent in the prior year. The remainder of Zargon's natural gas production was sold by spot sale contracts and Alberta index prices were received. In 2004, Zargon continued with an ongoing trend to develop new sources of natural gas production which receives spot sale natural gas prices and is not subject to aggregator contract prices.

HEDGING ACTIVITIES

Zargon's commodity price risk management policy uses forward sales, options, puts and costless collars for, on average, 20 to 35 percent of our oil and natural gas working interest production in order to partially offset the effects of large price fluctuations. As both Canadian oil and natural gas field prices are closely correlated to US dollar denominated markets, Zargon will also place US/Cdn. currency exchange hedges when considered prudent. Because our hedging strategy is protective in nature and is designed to guard the Trust against extreme effects from sudden falls in prices and revenues, upward price spikes and trends tend to produce overall losses. For 2004, the total hedging loss was $4.57 million compared to a loss of $2.88 million in 2003 and a gain of $0.67 million in 2002. Of the 2004 loss, $4.01 million (equivalent to a reduction of $3.20 per barrel) is related to oil hedges and $0.56 million (equivalent to a reduction of $0.05 per thousand cubic feet) was related to gas hedges. In 2004, oil prices increased throughout the year, peaking in the month of October. Natural gas prices were volatile during the year but they did not have the same upward trend as experienced by oil prices. The Trust also entered into fixed price physical contracts which created a gain of $0.25 million (equivalent to an increase of $0.02 per thousand cubic feet) in 2004. Gains or losses on fixed price physical contracts are included in petroleum and natural gas revenue in the statement of earnings. As at December 31, 2004, the Trust had the following outstanding commodity price risk management contracts:

	Volume	Rate	Price	Range of Terms
Financial Hedges				
Oil swaps	27,000 bbl	300 bbl/d	$35.45 US/bbl	Jan. 1/05–Mar. 31/05
	146,000 bbl	400 bbl/d	$44.05 US/bbl	Jan. 1/05–Dec. 31/05
Oil collars	54,300 bbl	300 bbl/d	$43.50 Cdn/bbl Put $54.50 Cdn/bbl Call	Jan. 1/05–Jun. 30/05
	55,000 bbl	200 bbl/d	$37.00 US/bbl Put $44.40 US/bbl Call	Apr. 1/05–Dec. 31/05
	36,200 bbl	200 bbl/d	$36.00 US/bbl Put $48.40 US/bbl Call	Jan. 1/06–Jun. 30/06
Natural gas swaps	180,000 gj	2,000 gj/d	$6.27/gj	Jan. 1/05–Mar. 31/05
	856,000 gj	4,000 gj/d	$6.49/gj	Apr. 1/05–Oct. 31/05
Natural gas collars	180,000 gj	2,000 gj/d	$6.75/gj Put $9.55/gj Call	Jan. 1/05–Mar. 31/05
	180,000 gj	2,000 gj/d	$6.75/gj Put $9.80/gj Call	Jan. 1/05–Mar. 31/05
	453,000 gj	3,000 gj/d	$5.90/gj Put $10.00/gj Call	Nov. 1/05–Mar. 31/06
	428,000 gj	2,000 gj/d	$6.00/gj Put $8.01/gj Call	Apr. 1/05–Oct. 31/05
Natural gas put	428,000 gj	2,000 gj/d	$5.10/gj	Apr. 1/05–Oct. 31/05
Physical Hedges				
Natural gas swaps	180,000 gj	2,000 gj/d	$8.35/gj	Jan. 1/05–Mar. 31/05
Natural gas put	428,000 gj	2,000 gj/d	$6.05/gj	Apr. 1/05–Oct. 31/05

ROYALTIES

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include credits received through the Alberta Royalty Tax Credit (ARTC) program, the cost of the Saskatchewan Resource Surcharge (SRC) and the cost of North Dakota state taxes. During 2004, total royalties were $28.05 million, an increase of 25 percent from $22.51 million in 2003. Royalties as a percentage of gross revenue (before hedging adjustments) were 22.6 percent in 2004 compared to 22.1 percent in 2003 and 20.6 percent in 2002. On a commodity basis, oil royalties averaged 21.5 percent (before hedging) in 2004, a small increase from the previous year's average of 20.2 percent. Natural gas royalties averaged 23.5 percent, unchanged from the prior year.

During 2004, 59 percent of the total royalties were paid to provincial and state governments, with the remainder paid to freehold owners and other third parties. Royalties payable to the Province of Alberta on qualifying properties are reduced through the ARTC program. Zargon earned the maximum $0.50 million ARTC rebate in 2004, which is the same amount received in 2003, compared to $0.32 million received in 2002. The SRC charges were $0.64 million in 2004, up from $0.53 million in the prior year and $0.52 million in 2002. North Dakota state taxes increased to $1.25 million in 2004 from $0.52 million in the prior year, primarily due to increased prices for oil, as well as increased production in the state.

PRODUCTION EXPENSES

Zargon's production expenses increased 26 percent to $21.69 million in 2004 from $17.20 million in 2003. On a unit of production basis, production expenses increased 14 percent to $7.21 per barrel of equivalent from $6.33 in 2003 ($6.75 in 2002).

Natural gas production expenses in 2004 rose 18 percent to $0.84 per thousand cubic feet from $0.71 per thousand cubic feet in 2003. The primary reasons for the increase are due to increased third-party processing costs for new gas discoveries in areas where Zargon does not own processing facilities, increased rentals for compression equipment, increased chemical and lubricant costs for field site treatment of sour gas wells and also the industry-wide trend to higher operating costs.

Oil production expenses also rose in 2004 to $10.30 per barrel, an increase of 15 percent from $8.95 per barrel in 2003. With the strong oil prices during the year, efforts were made to reactivate previously uneconomic oil production, which caused additional well servicing and workover costs. Also, chemicals, fuel and weather related road maintenance costs increased during the year.

Due to the high levels of industry activity caused by the high commodity price environment, there is increasing upward pressure on per unit operating costs. This trend is expected to continue if industry activity levels continue at the current record levels. In 2003, Zargon was able to deliver a cost improvement on a per unit of production basis over the prior year through the disposition of smaller, higher cost properties. In 2004, Zargon's costs increased substantially due in general to the effect of industry-wide higher cost trends and due in particular to the impact of the addition of new higher cost natural gas and oil production volumes. For 2005, Zargon expects the trend of increasing costs to continue as the demand for services is expected to continue at unprecedented levels.

OPERATING NETBACKS

The average oil price received after hedges in 2004 of $42.17 per barrel was 18 percent higher than the $35.79 per barrel received in 2003, while the average natural gas price received after hedges in 2004 of $6.32 per thousand cubic feet was three percent above the $6.13 per thousand cubic feet received in 2002. Operating netbacks increased commensurately. Oil and natural gas liquids netbacks rose 14 percent to $22.10 per barrel from $19.42 per barrel in 2003. Natural gas netbacks increased one percent to $3.98 per thousand cubic feet from $3.93 per thousand cubic feet in 2003. On a barrel of oil equivalent basis, 2004 operating netbacks rose seven percent to $23.15 from $21.73 in 2003.

OPERATING NETBACKS

	2004		2003	
	Oil and Liquids ($/bbl)	**Natural Gas ($/mcf)**	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)
Production revenue	**45.37**	**6.37**	36.66	6.33
Hedging	**(3.20)**	**(0.05)**	(0.87)	(0.20)
Royalties	**(9.77)**	**(1.50)**	(7.42)	(1.49)
Production costs	**(10.30)**	**(0.84)**	(8.95)	(0.71)
Operating netbacks	**22.10**	**3.98**	19.42	3.93

GENERAL AND ADMINISTRATIVE EXPENSES

Gross general and administrative costs increased 22 percent in 2004 to $7.23 million from $5.94 million in 2003. On a unit of production basis, net general and administrative costs increased 12 percent to $1.45 per barrel of equivalent, compared to $1.30 per barrel in 2003 and $1.49 per barrel in 2002. In 2004, the increased general and administrative costs on a per unit of production basis were due to increased staff costs, performance-based compensation costs, increased regulatory reporting requirements and the additional legal and other outside advisory costs of operating as a trust. In the prior year, the improvement in per barrel of equivalent costs was due to an increase in production volumes and an increase in capital program overhead recoveries. Going forward in a sustainable trust model, Zargon will attempt to maintain its general and administrative costs on a per unit of production basis at current levels.

GENERAL AND ADMINISTRATIVE EXPENSES

($ million, except as noted)	2004	2003	2002
Gross general and administrative expense	**7.23**	5.94	5.06
Overhead recoveries	**(2.87)**	(2.40)	(1.61)
Net general and administrative expense	**4.36**	3.54	3.45
Net expense after recoveries ($/boe)	**1.45**	1.30	1.49
Number of office employees at year-end	**35**	34	30

INTEREST EXPENSE

Zargon's borrowings are through its bank line of credit. Interest charges were $0.44 million compared to $0.77 million in 2003. A reduction in the average debt level is the primary reason for the reduction in interest charges. Zargon's effective interest rate was 4.9 percent on an average bank debt of $8.88 million in 2004, compared to 4.5 percent on an average bank debt of $17.19 million in 2003 and 4.1 percent on an average bank debt of $26.72 million in 2002. At year-end 2004, Zargon's bank debt, net of working capital, totalled $23.37 million, up 78 percent from $13.09 million at December 31, 2003.

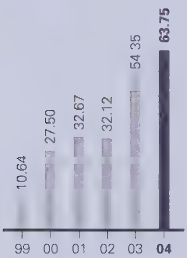
CAPITAL AND CURRENT INCOME TAXES

During 2004, Zargon incurred $1.11 million of current income taxes compared to $0.41 million in 2003. The increase is primarily due to current taxes incurred in the United States of $0.61 million. If high oil prices continue, there may be similar United States current income taxes payable annually, that will be somewhat modified by Zargon's United States capital program activity levels. The remaining amounts of current income taxes relate to federal and provincial capital taxes, which were $0.50 million in 2004 compared to $0.41 million in 2003. Tax pools as at December 31, 2004 were approximately $79 million. The Trust is a taxable entity under the Income Tax Act of Canada and is taxable only on the income that is not distributed or declared distributable to unitholders. It is anticipated that sufficient distributions will be made to eliminate current Canadian income tax. For Canadian income tax purposes, distributions are currently estimated to be 100 percent taxable income to unitholders.

TRUST NETBACKS

Historically high oil prices and the continued strength of natural gas prices in 2004 resulted in higher revenue netbacks and operating netbacks. On a barrel of equivalent basis, revenue of $41.20 in 2004 was 10 percent higher than the prior year and operating netbacks as well as cash flow netbacks increased seven percent and six percent over the prior year to $23.15 and $21.18 per barrel of equivalent, respectively.

CASH FLOW FROM OPERATIONS
($ million)



CASH FLOW NETBACKS
($/boe)

TRUST NETBACKS

($/boe)	2004	2003	2002
Petroleum and natural gas revenue	**41.20**	37.40	28.28
Hedging	**(1.52)**	(1.06)	0.29
Royalties	**(9.32)**	(8.28)	(5.83)
Production costs	**(7.21)**	(6.33)	(6.75)
Operating netbacks	**23.15**	21.73	15.99
General and administrative	**(1.45)**	(1.30)	(1.49)
Interest	**(0.15)**	(0.28)	(0.47)
Capital and current income taxes	**(0.37)**	(0.15)	(0.17)
Cash flow netbacks	**21.18**	20.00	13.86
Depletion and depreciation [1]	**(9.11)**	(7.23)	(6.07)
Accretion of asset retirement obligations [1]	**(0.36)**	(0.43)	(0.31)
Unit-based compensation	**(1.22)**	(0.10)	–
Unrealized foreign exchange	**0.19**	0.11	(0.03)
Future income taxes [1]	**(3.20)**	(3.38)	(2.83)
Earnings before non-controlling interest [1]	**7.48**	8.97	4.62
Non-controlling interest	**(0.62)**	–	–
Net earnings [1]	**6.86**	8.97	4.62

1. Comparative period numbers reflect the retroactive restatements due to a change in accounting policy.

CASH FLOW FROM OPERATIONS (see note at the beginning of the MD&A)

In 2004, a 10 percent gain in production volumes, in addition to increases of 24 percent in oil and natural gas liquids prices and one percent in natural gas prices, produced a 17 percent gain in cash flow from operations to $63.75 million, compared to $54.35 million in 2003 and $32.12 million in 2002. The corresponding cash flow per diluted unit was $3.40 in 2004, a 15 percent gain from $2.96 per diluted share in 2003 and compares to $1.81 in 2002. The diluted per unit statistics reflected a two percent increase in the weighted average outstanding units to 18.72 million in 2004 and a three percent increase in the weighted average number of outstanding shares to 18.37 million in 2003 from 17.79 million in 2002.

DEPLETION AND DEPRECIATION

In 2004, Zargon's depletion and depreciation provision increased 39 percent to $27.41 million, compared to $19.66 million in 2003 and $14.06 million in 2002. The higher charges reflect an increase of 10 percent in production volumes and a 26 percent increase in the charge on a per barrel of oil equivalent basis. This large increase in the per barrel of oil equivalent depletion and depreciation expense is primarily due to a December 31, 2003 year-over-year 14 percent reduction in the Trust's proved reserves as calculated under the new policies of National Instrument 51-101.

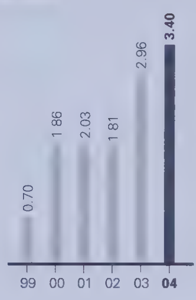
Depletion and depreciation charges calculated on a unit of production method are based on total proved reserves with a conversion of six thousand cubic feet of natural gas being equivalent to one barrel of oil. The 2004 depletion calculation includes $6.41 million of future capital expenditures to develop the Trust's reserves, but excludes $14.68 million of unproven properties relating to undeveloped land.

Zargon's depletion and depreciation, on a barrel of equivalent basis, increased 26 percent in 2004 to $9.11 from $7.23 in 2003 and $6.07 in 2002. Depletion and depreciation rates will be subject to continuing upward pressure as industry finding and development costs increase to reflect the new economics of the recent trends to substantially higher commodity prices.

ACCRETION OF ASSET RETIREMENT OBLIGATIONS

In 2003, the CICA approved section 3110 (Asset Retirement Obligations) effectively requires site restoration expense to be treated as a discounted future liability that is recognized in the balance sheet and amortized over the useful life of the related assets. The liability accretes until the retirement obligations are settled. Zargon retroactively adopted this standard effective January 1, 2004 and the expense line formerly termed Site Restoration is now called Accretion of Asset Retirement Obligations. For the year ended December 31, 2004, the non-cash accretion expense is $1.08 million compared to $1.17 million in 2003 and $0.72 million in 2002. The significant assumptions used in this calculation are a credit adjusted risk-free rate of 8.5 percent, an inflation rate of two percent and the payments to settle the retirement obligations will be made over the next 30 years with the majority of the costs being incurred after 2012. The estimated net present value of the total asset retirement obligation is estimated to be $14.39 million as at December 31, 2004, based on a total future liability of $59.12 million.

CASH FLOW PER UNIT ($/unit – diluted)



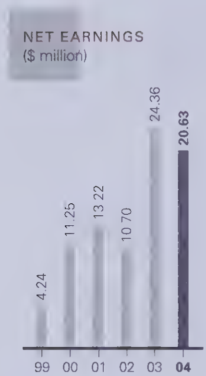
UNIT-BASED COMPENSATION

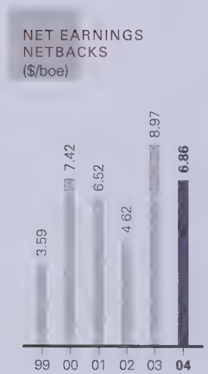
Unit-based compensation was $3.68 million in 2004 or $3.42 million higher than compared to $0.26 million in 2003. Of this amount, $2.17 million is related to a one-time charge for the accelerated vesting of stock options related to the July 15, 2004 Arrangement. The remainder is primarily the expense for the new trust unit rights incentive plan, which is calculated using the intrinsic value method which is based on the amount that the market price of the trust unit right exceeds the grant price for the rights issued. Prior to the effective date of the Plan of Arrangement, expensing of stock-based compensation benefits in the consolidated statement of earnings was calculated using the Black-Scholes option-pricing model. These non-cash expenses will be recurring charges in future years if Zargon continues to grant employee and director trust unit rights.

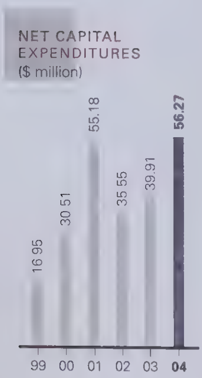
The trust unit rights incentive plan allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The Trust is authorized to issue up to 1.82 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust, and the plan allows for the holder of rights to either exercise the right based on the original grant price or on the original grant price reduced by a portion of the future distributions. Unit right grant prices approximate the market price for the trust units on the date the unit rights are issued. Trust unit rights granted under the plan vest over a three-year period and expire five years from the grant date.

FUTURE INCOME TAXES

Zargon's 2004 future tax expense increased five percent to $9.64 million from $9.19 million in 2003. The effective future tax rate in 2004 was 29.0 percent compared to 27.1 percent in 2003 and 37.2 percent in 2002. Effectively, Zargon's future tax obligations are reduced as distributions are made from the Trust, and consequently it is anticipated that Zargon's effective 2005 future tax rate will continue to decline in the Trust's first full year of operations. Comparisons with the 2003 period are distorted by the significant one-time federal tax rate adjustment that was booked to future taxes in 2003. In 2003, Royal Assent was received, thereby legislating certain federal reductions in corporate tax rates over a five-year period commencing in 2003. The rate changes incorporate a reduction in federal tax rates. The future tax impact related to reorganization costs of $0.49 million was charged to accumulated earnings.







NET EARNINGS

Zargon's 2004 net earnings were $20.63 million, a 15 percent reduction from $24.36 million in 2003. The 2002 net earnings were $10.70 million. The very strong 2003 increase was due primarily to the 69 percent increase in cash flow from operations and secondarily to the downward adjustment made in the 2003 future tax provision, which effectively added about $4.31 million to net earnings. On a per diluted unit basis, 2004 net earnings were $1.20 compared to $1.33 in 2003 and $0.60 in 2002.

On a barrel of equivalent, the 2004 net earnings were $6.86 compared to $8.97 in 2003 and $4.62 in 2002. In 2004, net earnings were 32 percent of cash flow. Reflecting primarily the adjustment in future tax calculations, the 2003 net earnings represented 45 percent of cash flow compared to 33 percent of cash flow in 2002.

CAPITAL EXPENDITURES

Net capital expenditures in 2004 of $56.27 million increased 41 percent over $39.91 million in 2003. This increase was due to a very active drilling program of 60 gross (49.5 net) wells for the year and the net $11.81 million purchase of producing Saskatchewan oil properties in the Williston Basin core area. Drilling and completion expenditures were up 56 percent to $26.94 million. Of the total 2004 net capital expenditures, $22.12 million was expended on West Central Alberta, $14.57 million on Alberta Plains and $19.58 million on Williston Basin properties.

CAPITAL EXPENDITURES

($ million)	2004	2003	2002
Undeveloped land	**3.84**	6.98	4.46
Geological and geophysical (seismic)	**5.26**	5.69	2.47
Drilling and completion of wells	**26.94**	17.30	12.49
Well equipment and facilities	**8.42**	7.33	4.48
Exploration and development	**44.46**	37.30	23.90
Property acquisitions	**12.09**	7.83	7.39
Property dispositions	**(0.28)**	(5.22)	(3.13)
Net property acquisitions	**11.81**	2.61	4.26
Corporate acquisitions assigned to property and equipment	**–**	–	7.39
Total net capital expenditures	**56.27**	39.91	35.55

Liquidity and Capital Resources

Zargon relies on three sources of funding:

- Internally generated cash flow provides the basic level of funding for the Trust's annual capital expenditures program and for distributions to unitholders.
- Debt may be utilized for acquisitions or to expand capital programs when it is deemed appropriate. The Trust has a $50 million revolving demand credit facility. As at December 31, 2004, $35.77 million or 72 percent of this line is unutilized. The Trust has followed and intends to maintain a conservative debt policy.
- New equity, if available and if on favourable terms, can be utilized for acquisitions or to expand capital programs.

In 2004, cash flow from operations of $63.75 million, proceeds from the exercise of stock options of $2.87 million and the increase in bank debt covered the capital program, costs incurred for the trust reorganization and the cash distributions to unitholders.

CAPITAL SOURCES

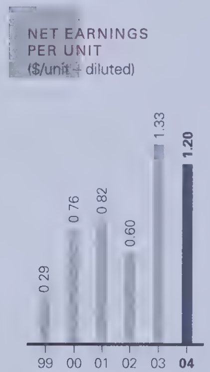
($million)	2004	2003	2002
Cash flow from operations	**63.75**	54.35	32.12
Changes in working capital and other	**2.54**	2.66	(3.58)
Change in bank indebtedness	**7.25**	(18.30)	1.14
Reorganization costs	**(9.44)**	–	–
Cash distributions	**(10.70)**	–	–
Issuance of common shares	**2.87**	1.20	5.87
Total capital sources	**56.27**	39.91	35.55

CASH FLOW FROM OPERATIONS

It is anticipated that Zargon's 2005 capital budget and cash distributions to unitholders will be financed through the Trust's cash flow from operations. Cash flow is partially influenced by factors that the Trust cannot control, such as commodity prices, the US/Canadian dollar exchange rates and interest rates. Zargon's 2005 estimated sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

CASH FLOW SENSITIVITY SUMMARY

	Change in 2005 Cash Flow ($ million)	($/unit)
Change of $1.00 US/bbl in the price of WTI oil	1.00	0.05
Change in oil production of 100 bbl/d	0.64	0.03
Change of $0.10 US/mcf in the price of NYMEX natural gas	0.89	0.04
Change in natural gas production of one mmcf/d	1.41	0.07
Change in $0.01 in the $US/$Cdn exchange rate	1.14	0.06



BANK INDEBTEDNESS

At December 31, 2004, bank debt was $14.23 million, an increase of 104 percent from the prior year-end amount of $6.98 million. In accordance with Canadian GAAP, the revolving demand bank debt is treated as a current liability.

Zargon's combined debt and working capital deficiency of $23.37 million at December 31, 2004 was equivalent to 37 percent of the 2004 cash flow from operations of $63.75 million. At December 31, 2003 the combined debt and working capital deficiency was $13.09 million, equivalent to 24 percent of 2003 cash flow from operations.

EQUITY

At March 14, 2005, Zargon had 15.665 million trust units and 2.913 million exchangeable shares outstanding. Assuming full conversion of exchangeable shares at the effective exchange ratio of 1.03726, there would be 18.687 million total trust units outstanding at this date. Pursuant to the new trust unit rights incentive plan, there are currently an additional 0.537 million trust unit rights issued and outstanding.

During 2004, 17.75 million Zargon trust units and common shares traded on The Toronto Stock Exchange with a high of $24.90 per unit, a low of $13.00 per share and a unit closing price of $23.85 per unit. The 2004 trading statistics show a 272 percent year-over-year increase in trading volume, and a 77 percent increase in the closing stock price. Zargon's market capitalization (including the market value of exchangeable shares) at year-end 2004 was approximately $444 million, compared to approximately $243 million at the end of 2003.

SEGMENTED GEOGRAPHIC INFORMATION

In calendar 2004 and 2003, approximately 88 percent of Zargon's combined petroleum and natural gas revenue came from Western Canada (Alberta, Saskatchewan and Manitoba) properties, with the remaining 12 percent of revenues generated in the United States (North Dakota and Montana).

Off Balance Sheet Arrangements

The Trust has no guarantees or off-balance sheet arrangements, except for letters of credit which have been issued in the normal course of business of approximately $0.46 million as at December 31, 2004.

Related Party Transactions

During the year, the Trust paid $0.15 million for consulting fees to a company owned by the Chairman of the Board, $0.05 million for vehicle leasing costs to a company associated with a member of the Board of Directors and $0.53 million for legal fees to a law firm associated with a member of the Board of Directors. All amounts were based on normal commercial terms and conditions.

Contractual Obligations

Zargon has certain contractual obligations relating to the lease of head office space, field operating leases and transportation contracts that extend for longer than one year as set out in the table below.

($ million)	Total	2005	2006 to 2007	2008 to 2009	Therafter
Head office lease and other	1.64	0.64	0.97	0.03	–
Field operating leases	0.75	0.75	–	–	–
Transportation contracts	0.73	0.49	0.17	0.07	–
	3.12	1.88	1.14	0.10	–

Critical Accounting Estimates

The preparation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. Zargon's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. The critical estimates are discussed below:

PETROLEUM AND NATURAL GAS RESERVES

All of Zargon's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels, and changes in costs and commodity prices.

FULL COST ACCOUNTING

Zargon follows the full cost method of accounting for petroleum and natural gas operations as outlined in Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting – Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit-of-production method based on estimated proved oil and natural gas reserves.

In applying the full cost method, Zargon calculates a ceiling test on a quarterly basis to ensure that the net carrying value of petroleum and natural gas assets do not exceed the estimated undiscounted future net cash flows from production of proved reserves. Accordingly, the Trust must base this calculation of future net cash flows on estimated forecasted sales prices, costs and regulations in effect at the period end. AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flows from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, Zargon adopted CICA Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Trust's property, plant and equipment. Under this policy, the Trust is required to provide for future removal and site restoration costs. The Trust must estimate these costs in accordance with existing laws, contracts or other policies and must also estimate a credit adjusted risk-free rate and inflation rate in this calculation. These estimated costs are charged to earnings and the appropriate liability account over the expected life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

INCOME TAX ACCOUNTING

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Recent Canadian Accounting Pronouncements

During 2004, the following new or amended standards and guidelines were issued:

EXCHANGEABLE SECURITIES ISSUED BY SUBSIDIARIES OF INCOME TRUSTS

On January 19, 2005 the CICA issued revised draft EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity.

In accordance with the transitional provisions of EIC-151, the Trust has retroactively restated prior periods dating back to the Plan of Arrangement dated July 15, 2004. As a result of this change in accounting policy, the Trust has reflected a non-controlling interest of $9.53 million on the Trust's consolidated balance sheet as at December 31, 2004. Consolidated net earnings have been reduced for net income attributable to the non-controlling interest of $1.87 million in 2004. In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2004 resulted in an increase in property and equipment of $11.28 million, an increase of unitholders' equity by $0.62 million, and an increase in future income tax liability of $3.00 million. Cash flow was not impacted by this change.

HEDGE ACCOUNTING

The CICA issued Accounting Guideline 13 ("AcG-13") "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. In addition, the CICA simultaneously amended EIC-128, "Accounting for Trading, Speculative or Non-Trading Derivative Financial Instruments" to require that all derivative instruments that do not qualify as a hedge under AcG-13, or are not designated as a hedge, be recorded in the consolidated balance sheet as either an asset or a liability with the changes in fair value recognized in earnings.

The Trust uses derivative instruments to reduce its exposure to fluctuations in commodity prices, foreign exchange, and interest rates. The Trust formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. The Trust also formally assesses whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

Since the Trust has designated its derivative instruments as hedges, the implementation of this accounting policy did not have any impact on the consolidated financial statements of the Trust.

PETROLEUM AND NATURAL GAS ASSETS – FULL COST ACCOUNTING

The new CICA Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16") is effective for fiscal years beginning on or after January 1, 2004. The most significant change between AcG-16 and the former guideline is that AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flows from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate. This differs from the former cost recovery ceiling test that used undiscounted cash flows, and constant prices, less general and administrative and financing costs. No write-down of the Trust's petroleum and natural gas properties was required when the new guideline was adopted on January 1, 2004 or as at December 31, 2004.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, Zargon adopted CICA Section 3110, "Asset Retirement Obligations," which requires liability recognition for retirement obligations associated with the Trust's property, plant and equipment. The obligations are initially measured at estimated fair value, which is the discounted future value of the estimated liability. The fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful lives. The liability accretes until the retirement obligations are settled. Section 3110 is effective for fiscal years beginning on or after January 1, 2004 on a retroactive basis with restatement of prior periods. The site restoration liability on the balance sheet at December 31, 2003 was replaced with a new "Asset Retirement Obligation" liability in the amount of $12.19 million on January 1, 2004.

Business Risks And Outlook

BUSINESS RISKS

Zargon's external business risks arise from the uncertainty of oil and natural gas pricing, the uncertainty of interest and exchange rates, environmental and safety issues, and financial and liquidity considerations. Additional risk arises from the production performance of existing properties (including natural decline), the changes in tax, royalty and other regulatory standards and uncertain results from capital expenditure programs.

Oil and natural gas prices may fluctuate widely in response to many factors such as global and North American supply and demand, economic conditions, weather conditions, political stability, the supply and price of imported oil and liquefied natural gas, production and storage levels of North American natural gas, and government regulations. Zargon attempts to minimize pricing and currency exchange uncertainty with a risk management program that encompasses a variety of financial instruments. These include forward sales of oil and natural gas production (either through financial derivative transactions such as swaps or by physical contracts), put options on both oil and natural gas, costless collars (in which some potential high price gain is given up in return for potential low price support) and US dollar currency hedges in different forms for up to 35 percent of its oil and natural gas production volumes. In general, the Trust seeks to use strategies that allow minimum price expectations to be met in order that distributions and capital programs can be funded. This strategy is designed mainly to protect the Trust against periods of unusually low commodity prices and by its nature is likely to produce significant hedging losses when prices are unusually high.

Environmental and safety risks are mitigated through compliance with provincial and federal environmental and safety regulations, by maintaining adequate insurance, and by adopting appropriate emergency response and employee safety procedures.

The Trust is subject to a broad range of laws and regulatory requirements. Changes in government regulations, including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates can have a significant impact on Zargon. Although Zargon has no control over these regulatory risks, the Trust actively monitors changes, participates in industry organizations and, when required, engages the assistance of third-party experts to assess the impact of such changes in the Trust's financial and operating results.

Financial and liquidity risks are reduced by limiting debt financing to conservative self-imposed debt to cash flow guidelines. Zargon maintains a low cash distribution to cash flow from operations ratio to ensure adequate funding is available for capital programs to sustain per unit production and reserves. Access to capital markets, if required for additional financing by either debt or equity issuances, is dependent upon maintaining strong performance and relationships with investors. A substantial portion of the Trust's accounts receivable are with companies in the oil and gas industry and are subject to normal industry credit risks. Management regularly monitors the ageing of receivable balances to mitigate this risk. With respect to financial instruments utilized for hedging purposes, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Zargon actively manages the risks of its capital programs and reserves by concentrating drilling and subsequent development activities in areas where it has demonstrated proven technical capabilities and understanding. Zargon's capital budget is managed to limit exposure so that significant capital is not risked on any one project or concept.

CORPORATE OUTLOOK

As a sustainable trust Zargon is committed to maintaining reserves, production and distributions per unit in the context of distributing approximately 50 percent of its cash flows to unitholders. For calendar 2005, Zargon has budgeted $40 million of capital expenditures allocated to natural gas exploration and oil exploitation. This amount does not include any allocation for opportunistic corporate or property acquisitions which, if available, would be funded by bank debt or equity issues.

SELECTED QUARTERLY INFORMATION [1]

	2004				2003			
($ million, except per unit amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas revenue	**32.90**	**32.41**	**30.96**	**27.70**	24.51	23.76	24.20	29.19
Cash flow from operations	**15.36**	**16.13**	**16.53**	**15.73**	13.24	12.34	13.53	15.23
Per unit – diluted [1]	**0.82**	**0.87**	**0.88**	**0.84**	0.72	0.67	0.74	0.84
Net earnings [1]	**5.33**	**4.22**	**5.54**	**5.54**	4.10	4.44	9.17	6.65
Per unit – diluted [1]	**0.34**	**0.28**	**0.29**	**0.30**	0.22	0.24	0.50	0.36
Cash distributions	**6.43**	**4.27**	**–**	**–**	–	–	–	–
Cash distribution – per trust unit	**0.42**	**0.28**	**–**	**–**	–	–	–	–
Net capital expenditures	**15.25**	**23.64**	**7.61**	**9.77**	12.84	12.11	8.10	6.86
Total assets [1]	**226.96**	**215.23**	**189.80**	**186.18**	181.05	172.81	165.98	165.12
Bank indebtedness	**14.23**	**9.77**	**–**	**3.67**	6.98	8.92	11.47	20.78

1. Comparative period numbers reflect the retroactive restatements due to changes in accounting policies.

Fourth Quarter 2004 Highlights

During the fourth quarter of 2004, Zargon increased petroleum and natural gas revenues by two percent or $0.49 million to $32.90 million from the third quarter of 2004. Production for the fourth quarter of 2004 was 8,440 barrels of equivalent per day compared to 8,405 barrels of equivalent per day in the third quarter of 2004 and slightly under the guidance of 8,500 barrels of equivalent per day that was given in Zargon's third quarter report. Oil production increased six percent to 3,618 barrels per day and natural gas production decreased three percent to 28.93 million cubic feet per day compared to the prior quarter. Average prices received during the fourth quarter, before hedging, were $47.13 per barrel for oil and $6.46 per thousand cubic feet for natural gas, a five percent reduction and a six percent increase respectively, compared to the third quarter of 2004. During the quarter, Zargon's field price differential for its blended 30 degree API crude oil stream increased to $10.58 per barrel less than the Edmonton reference crude oil price. This differential compares to $6.09 per barrel for the first nine months of 2004 and is a response to reduced demand for Zargon's medium grades of crude oil during the quarter.

Cash flow from operations was $15.36 million in the fourth quarter, a decrease of five percent or $0.77 million from the prior quarter. The primary factors that caused this decrease from the prior quarter are as follows:

- Hedging losses increased by $0.13 million to $1.56 million compared to $1.43 million, a nine percent increase from the prior quarter. The primary reason for the increase in the fourth quarter was due to losses on oil hedging contracts as a result of the continuing strength of oil prices throughout the quarter.
- Royalties for the fourth quarter were $7.84 million, an increase of $0.45 million from the prior quarter. The average royalty rate for the quarter increased to 23.8 percent from 22.8 percent from the third quarter due to adjustments related to prior periods.
- Production expenses totalled $6.28 million for the quarter, a $0.51 million or nine percent increase from the third quarter of 2004. On a per barrel of oil equivalent basis, production expenses were $8.09 in the fourth quarter 2004 compared to $7.45 in the prior quarter, a nine percent increase. During the quarter, increased compression, treating and third-party processing costs were incurred for recently added natural gas production volumes. Increased costs were also incurred for well servicing and workovers related to oil production. Also, the fourth quarter included $0.26 million or $0.34 per barrel of equivalent of costs that related to prior periods.

- General and administrative expenses increased in the fourth quarter by $0.26 million over the third quarter of 2004. This is a 25 percent increase compared to the prior quarter and is primarily due to amounts for performance-based compensation for employees.
- Interest expense in the fourth quarter was $0.21 million, an increase of 109 percent or $0.10 million from the prior quarter. This increase is primarily due to the increase in the average debt level for the fourth quarter to $14.62 million compared to $9.35 million in the third quarter of 2004 and costs incurred in relation to the renewal of the Trust's credit facility in the fourth quarter.
- Capital and current income taxes decreased by $0.21 million or 40 percent from the third quarter of 2004. The decrease was due to United States current income taxes incurred in the third quarter of 2004.

Net earnings for the quarter increased $1.11 million to $5.33 million, a 26 percent increase compared to the third quarter 2004 earnings of $4.22 million. Net earnings track the cash flow from operations for the respective periods modified by non-cash charges, which included the following for the fourth quarter of 2004:

- Unit-based compensation expense decreased by $1.95 million during the fourth quarter of 2004 to $0.71 million, as the third quarter included the one-time charge of $2.17 million pertaining to the accelerated vesting of stock options related to the July 15, 2004 Arrangement.
- Depletion and depreciation expense increased by $0.76 million to $7.77 million in the fourth quarter. The additional expense resulted from the use of an updated depletion and depreciation rate of $10.00 per barrel of equivalent, compared to the prior quarter's $9.06 per barrel of equivalent charge. The increased per unit charges are calculated on the basis of the recently completed 2004 year-end reserve appraisal prepared by independent engineers that reflects Zargon's and the ongoing industry's trend to higher finding and development costs, which are commensurate with the new economics of this current era of substantially higher commodity prices.
- Future income tax expense was $0.57 million during the quarter, a reduction of $0.81 million from the third quarter of 2004. As cash distributions are made from the Trust, the effective future tax rate is lowered. During the third quarter of 2004, only two months of distributions totalling $4.27 million were made, compared to three months of distributions made in the fourth quarter of 2004 totalling $6.43 million. This increase in the amount of distributions resulted in the lower amount of future taxes in the fourth quarter of 2004.
- Non-controlling interest related to exchangeable shares increased to $1.01 million in the fourth quarter, from $0.86 million in the third quarter (on a restated basis). The increase was due to an increase in net earnings before non-controlling interest in the fourth quarter.

Net capital expenditures were $15.25 million during the fourth quarter of 2004, a 35 percent reduction from the prior quarter amount of $23.64 million. If the third quarter's $10 million Southeast Saskatchewan oil property acquisition is excluded, the fourth quarter capital program showed a 12 percent increase over the third quarter levels. During the fourth quarter of 2004, 16.1 net wells were drilled, compared to 15.2 net wells in the third quarter of 2004.

Additional Information

Additional information regarding the Trust and its business operations, including the Trust's Renewal Annual Information Form for December 31, 2004, is available on the Trust's SEDAR profile at www.sedar.com.

MANAGEMENT'S REPORT

The consolidated financial statements of Zargon Energy Trust were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements reliably report the Trust's operations and that the Trust's assets are safeguarded. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

Ernst & Young LLP, an independent chartered accountant firm, was appointed by a resolution of the unitholders to audit the financial statements of the Trust and provide an independent opinion. They have conducted an independent examination of the Trust's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors, has met with Ernst & Young LLP and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors, who have approved the consolidated financial statements.

	BC Heagy
C.H. Hansen	B.C. Heagy
President and Chief Executive Officer	Vice President, Finance and Chief Financial Officer

Calgary, Canada
March 14, 2005

AUDITORS' REPORT

To the Unitholders of Zargon Energy Trust

We have audited the consolidated balance sheets of Zargon Energy Trust as at December 31, 2004 and 2003 and the consolidated statements of earnings and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Calgary, Canada
March 14, 2005

Chartered Accountants

As at December 31 ($ thousand)	2004	2003 (restated – note 3)
ASSETS *[note 5]*		
Current		
Accounts receivable *[note 11]*	**14,275**	12,183
Prepaid expenses and deposits	**2,953**	980
	17,228	13,163
Property and equipment *[note 4]*	**209,736**	167,888
	226,964	181,051
LIABILITIES		
Current		
Bank indebtedness *[note 5]*	**14,230**	6,978
Accounts payable and accrued liabilities	**24,153**	19,277
Cash distributions payable	**2,210**	–
	40,593	26,255
Asset retirement obligations *[notes 3 and 6]*	**14,390**	12,194
Future income taxes *[note 9]*	**41,830**	30,133
	96,813	68,582
Commitments and contingencies *[notes 11, 12 and 13]*		
NON-CONTROLLING INTEREST		
Exchangeable shares *[notes 3 and 8]*	**9,529**	–
UNITHOLDERS' EQUITY		
Unitholders' capital/share capital *[note 7]*	**45,755**	42,200
Contributed surplus *[note 7]*	**1,170**	264
Accumulated earnings	**84,399**	70,005
Accumulated cash distributions *[note 16]*	**(10,702)**	–
	120,622	112,469
	226,964	181,051

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

J.O. McCutcheon
Director

W.J. Whelan
Director

For the years ended December 31 ($ thousand, except for per unit amounts)	2004	2003 (restated – note 3)
Revenue		
Petroleum and natural gas revenue	**123,968**	101,657
Hedging *[note 11]*	**(4,568)**	(2,882)
Royalties (net of Alberta Royalty Tax Credit)	**(28,047)**	(22,508)
	91,353	76,267
Expenses		
Production	**21,692**	17,201
General and administrative *[note 18]*	**4,358**	3,542
Unit-based compensation *[note 7]*	**3,682**	264
Interest	**440**	771
Unrealized foreign exchange (gain) loss	**(564)**	(297)
Accretion of asset retirement obligations *[notes 3 and 6]*	**1,076**	1,172
Depletion and depreciation	**27,414**	19,660
	58,098	42,313
Earnings before income taxes	**33,255**	33,954
Income taxes *[note 9]*		
Future	**9,639**	9,187
Current	**1,114**	406
	10,753	9,593
Earnings for the year before non-controlling interest	**22,502**	24,361
Non-controlling interest - exchangeable shares *[notes 3 and 8]*	**(1,870)**	–
Net earnings for the year	**20,632**	24,361
Accumulated earnings, beginning of year		
As previously reported	**70,125**	45,598
Retroactive application of change in accounting policy *[note 3]*	**(120)**	46
As restated	**70,005**	45,644
Reorganization costs *[note 17]*	**(6,238)**	–
Accumulated earnings, end of year	**84,399**	70,005
Net earnings per unit/per common share *[note 10]*		
Basic	**1.23**	1.37
Diluted	**1.20**	1.33

See accompanying notes to the consolidated financial statements.

For the years ended December 31 ($ thousand)	2004	2003 (restated – note 3)
Operating activities		
Net earnings for the year	**20,632**	24,361
Add (deduct) non-cash items:		
Non-controlling interest – exchangeable shares *[notes 3 and 8]*	**1,870**	–
Depletion and depreciation	**27,414**	19,660
Accretion of asset retirement obligations	**1,076**	1,172
Unit-based compensation *[note 7]*	**3,682**	264
Unrealized foreign exchange (gain) loss	**(564)**	(297)
Future income taxes	**9,639**	9,187
	63,749	54,347
Asset retirement expenditures	**(414)**	(287)
Changes in non-cash working capital	**19**	(936)
	63,354	53,124
Financing activities		
Advances (repayment) of bank indebtedness	**7,252**	(18,301)
Cash distributions to unitholders	**(10,702)**	–
Exercise of stock options	**2,867**	1,203
Changes in non-cash working capital	**2,148**	–
	1,565	(17,098)
Investing activities		
Additions to property and equipment	**(56,553)**	(45,124)
Proceeds on disposal of property and equipment	**280**	5,215
Reorganization costs *[note 17]*	**(9,443)**	–
Changes in non-cash working capital	**797**	3,883
	(64,919)	(36,026)
Change in cash, and cash end of year	**–**	–

See supplementary information contained in Note 14.

See accompanying notes to the consolidated financial statements.

For the years ended December 31, 2004 and 2003.
All amounts are stated in Canadian dollars unless otherwise noted.

1. Structure of the Trust

On July 15, 2004, Zargon Oil & Gas Ltd. (the "Company") was reorganized into Zargon Energy Trust (the "Trust" or "Zargon") as part of a Plan of Arrangement (the "Arrangement"). Shareholders of the Company received one trust unit or one exchangeable share for each common share held. All outstanding common share options were settled for cash prior to the completion of the reorganization. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive cash distributions paid, but rather, on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The trust units commenced trading on the TSX under the symbol "ZAR.UN" on July 21, 2004. The exchangeable shares commenced trading on the TSX under the symbol "ZOG.B" on August 4, 2004. The Trust is an unincorporated open-ended investment trust established under the laws of the Province of Alberta and was created pursuant to a trust indenture ("Trust Indenture"). Valiant Trust Company has been appointed trustee under the Trust Indenture.

The costs of the reorganization were $9.44 million and are described in note 17.

The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in Canada and the United States ("U.S.").

2. Summary of Significant Accounting Policies

CONSOLIDATION AND BASIS OF PRESENTATION

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

While the Trust commenced operations on July 15, 2004, these consolidated financial statements follow the continuity of interest basis of accounting as if the Trust had always existed. This basis is intended to provide unitholders with meaningful and comparative financial information. Also, certain comparative figures have been reclassified to conform with the current presentation.

The consolidated financial statements include the accounts of Zargon Energy Trust, all subsidiaries and a partnership. All subsidiaries and the partnership are directly or indirectly owned and their operations are fully reflected in the consolidated financial statements.

REVENUE RECOGNITION

Petroleum and natural gas revenue is recognized in earnings when reserves are produced and delivered to the purchaser.

JOINT OPERATIONS

The majority of the petroleum and natural gas operations of the Trust are conducted jointly with others, and accordingly, these financial statements reflect only the proportionate interests of the Trust in such activities.

PROPERTY AND EQUIPMENT

The Trust follows the full cost method of accounting for its oil and natural gas operations whereby all costs relating to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in separate cost centres for Canada and the United States. Such costs include land acquisition costs, annual carrying charges of non-producing properties, geological and geophysical costs, and costs of drilling and equipping wells.

Depletion and depreciation of petroleum and natural gas properties and equipment is computed using the unit of production method based on the estimated proved reserves of petroleum and natural gas before royalties determined by independent consultants. For purposes of this calculation, reserves are converted to common units on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil. A portion of the cost of petroleum and natural gas rights relating to undeveloped properties is excluded from depletion calculations. Twenty percent of the year-end balance of these costs is added to the depletion base each year. Proceeds on the disposal of petroleum and natural gas properties are applied against capitalized costs, with gains or losses not ordinarily recognized, unless such a disposal would result in a change in the depletion rate of 20 percent or more.

Depreciation of office equipment is provided using the declining balance method at an annual rate of 20 percent.

IMPAIRMENT TEST

The Trust applies an impairment test to petroleum and natural gas properties and equipment costs on an annual basis or as events or circumstances dictate. This impairment test is performed on both the Canadian and U.S. cost centres. An impairment loss exists when the carrying amount of the Trust's petroleum and natural gas properties and equipment exceeds the estimated undiscounted future net cash flows associated with the Trust's proved reserves (before royalties). If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the Trust's proved and probable reserves are charged to income. Reserves are determined pursuant to evaluation by independent engineers as dictated by National Instrument 51-101. The calculation of future net cash flow is based on future prices as estimated by management relative to benchmark prices in future markets discounted using a risk-free rate (see note 4).

ASSET RETIREMENT OBLIGATIONS

Zargon recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed in the period. Actual costs incurred upon the settlement of the ARO are charged against the liability. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

FINANCIAL INSTRUMENTS

Derivative financial instruments are utilized from time to time to reduce commodity price risk associated with the Trust's production of oil and natural gas. The base prices for the commodities are sometimes denominated in U.S. dollars and the Trust may also use such financial instruments to reduce the related foreign currency risk. Financial instruments may also be used from time to time to reduce interest rate risk on outstanding debt. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust follows a policy of using hedge instruments such as fixed price swaps, forward sales, puts, options and costless collars. The objective is to partially offset or mitigate the wide price swings commonly encountered in oil and natural gas commodities and in so doing protect a minimum level of cash flow in periods of low commodity prices. The Trust's policy is to designate each derivative financial instrument employed as a hedge of a specific portion of projected production over the term of the instrument. The Trust formally documents its risk management objectives and strategies for undertaking the hedged transactions, the hedging item, the nature of the specific risk exposures being hedged, the intended term of the hedge relationship, the method for assessing effectiveness and the method of accounting for the hedging relationship. The effectiveness of the derivative is assessed on an ongoing basis to ensure that the derivatives entered into are highly effective in offsetting changes in fair values of the hedged items. The instruments employed may be denominated in U.S. or Canadian dollars. The Trust believes the derivative financial instruments used are effective as hedges over their term. In the event that a designated hedged item ceases to exist, any realized or unrealized gain or loss on such derivative commodity instruments is recognized in income immediately. If the hedge relationship is terminated, either via ineffectiveness or via termination of the designation, gains or losses previously deferred continue to be deferred and recognized when they are realized.

In the case of forward sales, the instrument can sometimes be satisfied by physical delivery. In all other cases the instrument is satisfied by payments or charges calculated by referring published prices to the agreed reference price in the terms and manner set out in the contract and paid or received monthly. In the case of physical delivery, the payment is part of the normal revenue stream. All other payments or charges are accounted for monthly as adjustments to revenue received.

Interest rate swap agreements may be used from time to time to manage the floating interest rate on the Trust's revolving bank debt. Such agreements involve the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. At December 31, 2004 and 2003 the Trust had no such financial instruments.

Foreign currency swap agreements may be used from time to time to manage the risk inherent in producing commodities whose price is based directly or indirectly on U.S. dollars, using a notional principal equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, usually with monthly settlement. Foreign currency swap agreements are designated as hedges of revenue that is received in Canadian dollars, but whose amount is determined in foreign currency. At December 31, 2004 and 2003 the Trust had no such financial instruments.

Gains or losses from all contracts, other than forward sales settled by physical delivery, are recognized as hedging gains or losses when realized.

INCOME TAXES

The Trust follows the liability method of tax allocation in accounting for income taxes. Under this method, the Trust records future income taxes for the effect of any differences between the accounting and income tax basis of an asset or liability using income tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in net earnings in the period in which the change is substantively enacted.

FOREIGN CURRENCY TRANSLATION

The Trust uses the temporal method of foreign currency translation, whereby the monetary assets and liabilities recorded in a foreign currency are translated into Canadian dollars at year-end exchange rates, and non-monetary assets and liabilities at the exchange rates prevailing when the assets were acquired or liability incurred. Revenues and expenses are translated at the average rate of exchange for the year. Gains and losses on translation are included in the consolidated statements of earnings.

TRUST UNIT RIGHTS AND UNIT-BASED COMPENSATION

Under the Trust's unit rights incentive plan (the "Plan"), rights to purchase trust units are granted to directors, officers and employees at current market prices. Compensation expense for rights granted by the Trust subsequent to the Arrangement is based on the amount that the market price of the trust unit exceeds the original exercise price (grant price) for rights as at the date of the financial statements and is recognized in earnings over the vesting period of the Plan with an offsetting amount recorded to contributed surplus. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur. Stock options granted in 2003 and through to implementation of the Arrangement are accounted for in accordance with the fair value method of accounting for stock-based compensation, and as such, the cost of the option is charged to earnings with an offsetting amount recorded to contributed surplus, based on an estimate of the fair value using a Black-Scholes option-pricing model. No compensation expense has been recorded on options issued prior to 2003 (see note 7).

PER UNIT AMOUNTS

Per unit amounts are calculated using the weighted average number of trust units outstanding during the period. Diluted per unit amounts are calculated using the treasury stock method to determine the dilutive effect of unit-based compensation. The Trust follows the treasury stock method, which assumes that the proceeds received from "in-the-money" trust unit rights are used to repurchase units at the average market rate during the period. Diluted per unit amounts also include exchangeable shares using the "if-converted" method, whereby it is assumed the conversion of the exchangeable securities occurs at the beginning of the reporting period (or at the time of issuance if later).

MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property and equipment and the assessment of these assets for impairment are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

Inherent in the fair value calculation of asset retirement obligations, are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the property and equipment balance.

CASH DISTRIBUTIONS

The Trust declares monthly distributions of cash to unitholders of record on the last day of each calendar month. Pursuant to the Trust's policy, it will pay distributions to its unitholders subject to satisfying its financing covenants. Such distributions are recorded as distributions of equity upon declaration of the distribution.

3. Changes In Accounting Policies

EXCHANGEABLE SHARES – NON-CONTROLLING INTEREST

On January 19, 2005, the CICA issued revised draft EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity.

In accordance with the transitional provisions of EIC-151, the Trust has retroactively restated prior periods dating back to the Plan of Arrangement dated July 15, 2004. As a result of this change in accounting policy, the Trust has reflected a non-controlling interest of $9.53 million on the Trust's consolidated balance sheet as at December 31, 2004. Consolidated net earnings have been reduced for net income attributable to the non-controlling interest of $1.87 million in 2004. In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2004 resulted in an increase in property and equipment of $11.28 million, an increase of unitholders' equity by $0.62 million, and an increase in future income tax liability of $3.0 million. Cash flow was not impacted by this change.

FULL COST ACCOUNTING

On January 1, 2004, Zargon adopted the new CICA Accounting Guideline 16 "Oil and Gas Accounting – Full Cost". The new guideline modifies how the ceiling test is performed, and requires that cost centres be tested for recoverability using undiscounted future cash flows from proved reserves determined using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques, which incorporate risks and other uncertainties when determining expected cash flows. Since the fair values of the cost centres exceed the carrying value, there is no impact on the Trust's reported financial results as a result of applying the new Accounting Guideline 16.

ASSET RETIREMENT OBLIGATIONS

On January 1, 2004, Zargon retroactively adopted the Canadian accounting standard outlined in CICA Handbook Section 3110, "Asset Retirement Obligations". Previously, estimated future site restoration costs were provided for over the life of the proved reserves on a unit of production basis.

Under the new accounting standard, the Trust records the fair value of legal obligations associated with the retirement of long-lived tangible assets, such as petroleum and natural gas assets, in the period in which they are acquired or drilled and a corresponding increase in the carrying amount of the long-lived asset. The liability accretes until the Trust expects to settle the retirement obligation. The asset retirement costs assigned to the long-lived assets are depleted using the unit of production method. Actual costs to retire the tangible assets are deducted from the liability as incurred.

As required by the new standard, all prior periods have been restated for the change in accounting policy. The effect of this change on the consolidated balance sheet as of January 1, 2004 is an increase in net capital assets of $5.98 million, recognition of an asset retirement obligation liability of $12.19 million, elimination of the site restoration liability of $6.03 million, recognition of a future tax recovery of $0.06 million, and a decrease to retained earnings of $0.12 million. The impact on net earnings and per unit amounts for the year ended December 31, 2004 and 2003 is negligible as a result of adopting this new policy.

4. Property and Equipment

		2004	
($ thousand)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and equipment	**295,533**	**97,680**	**197,853**
Adjustment due to conversion of exchangeable shares (see note 3)	**11,279**	**–**	**11,279**
Office equipment	**1,304**	**700**	**604**
	308,116	**98,380**	**209,736**

		2003	
($ thousand) (restated - note 3)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and equipment	237,860	70,351	167,509
Office equipment	1,009	630	379
	238,869	70,981	167,888

At December 31, 2004, petroleum and natural gas properties and equipment include $14.7 million (2003 – $14.5 million) relating to undeveloped properties that have been excluded from the depletion calculation.

An impairment test calculation was performed on the Trust's petroleum and natural gas properties and equipment at December 31, 2004 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Trust's petroleum and natural gas properties and equipment. This impairment calculation was performed separately on both the Canadian and U.S. cost centres.

The following table outlines benchmark prices used in the impairment test at December 31, 2004:

Year	WTI Crude Oil ($US/bbl)	Exchange Rate $US/$Cdn	WTI Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/gj)
2005	42.60	0.83	51.33	6.02
2006	40.42	0.83	48.70	6.22
2007	39.11	0.83	47.12	5.85
2008	38.09	0.83	45.89	5.55
2009	37.37	0.83	45.02	5.26
2010 – 2014	37.35	0.83	45.00	5.09
Thereafter (inflation %)	2.0%	0.83	2.0%	2.0%

Actual prices used in the impairment test were adjusted for commodity price differentials specific to Zargon.

5. Bank Indebtedness

The Trust has a revolving demand credit facility that provides for a line of credit of $50.00 million bearing interest at prime (December 31, 2004 – 4.25 percent; 2003 – 4.50 percent) and has pledged an assignment of accounts receivable, a first floating charge on all of the Canadian assets and a fixed charge over certain property and equipment as collateral. In the normal course of operations Zargon enters into various letters of credit. At December 31, 2004, the approximate value of these letters of credit totalled $0.46 million (2003 – $0.50 million).

6. Asset Retirement Obligations

The total future asset retirement obligation was estimated by management based on Zargon's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. Zargon has estimated the net present value of its total asset retirement obligations to be $14.39 million (2003 – $12.19 million) as at December 31, 2004, based on a total future liability of $59.12 million (2003 – $50.85 million). These payments are expected to be made over the next 30 years with the majority of the costs being incurred after 2012. Zargon used a discount rate of 8.5 percent which is based on a risk-free rate adjusted for credit risk and an inflation rate of two percent to calculate the present value of the asset retirement obligation.

The following table reconciles Zargon's asset retirement obligation:

	Year Ended December 31,	
($ thousand)	2004	2003
Balance, beginning of year	**12,194**	10,560
Liabilities incurred	**1,696**	749
Liabilities settled	**(414)**	(287)
Accretion expense	**1,076**	1,172
Other	**(162)**	–
Balance, end of year	**14,390**	12,194

7. Unitholders' Equity

Pursuant to the Plan of Arrangement on July 15, 2004, 14.87 million units of the Trust and 3.66 million exchangeable shares (see note 8) of the Company were issued in exchange for all of the outstanding shares of the Company on a one-for-one basis.

COMMON SHARES OF ZARGON OIL & GAS LTD.

	December 31, 2004		December 31, 2003	
(no par value) (thousand)	Number of Shares	Amount ($)	Number of Shares	Amount ($)
Shares issued				
Balance, beginning of year	**17,992**	**42,200**	17,637	40,997
Stock options exercised for cash	**534**	**2,867**	355	1,203
Stock-based compensation recognized	**–**	**69**	–	–
Trust units issued	**(14,866)**	**(36,219)**	–	–
Exchangeable shares issued	**(3,660)**	**(8,917)**	–	–
Balance, end of year	**–**	**–**	17,992	42,200

The Trust is authorized to issue an unlimited number of voting trust units.

TRUST UNITS

	December 31, 2004	
(thousand)	Number of Units	Amount ($)
Units issued		
Issued pursuant to Plan of Arrangement July 15, 2004	**14,866**	**36,219**
Issued on conversion of exchangeable shares	**475**	**9,536**
Balance, end of year	**15,341**	**45,755**

COMPENSATION PLANS

A summary of the status of the Trust's compensation expense for the years ended December 31, 2004 and 2003 is presented below:

COMPENSATION EXPENSE

($ thousand)	Year Ended December 31, 2004	Year Ended December 31, 2003
Stock-based compensation expense prior to Plan of Arrangement July 15, 2004	**345**	264
Accelerated vesting of unvested stock options pursuant to the Arrangement	**2,167**	–
Unit-based compensation recognized subsequent to trust conversion	**1,170**	–
Balance, end of year	**3,682**	264

A summary of the status of the Trust's compensation plans as at December 31, 2004 and 2003 and changes during the years ended on those dates is presented below:

STOCK OPTIONS

As part of the Arrangement to reorganize Zargon Oil & Gas Ltd. into a Trust, all common share options, vested and unvested, were cancelled and the optionholders received a cash payment for the intrinsic value of the options.

	December 31, 2004		December 31, 2003	
	Number of Shares (thousand)	Weighted Average Exercise Price ($/stock option)	Number of Shares (thousand)	Weighted Average Exercise Price ($/stock option)
Outstanding at beginning of year	**1,297**	**7.05**	1,215	5.10
Granted	**430**	**16.00**	459	9.50
Exercised	**(534)**	**5.39**	(355)	3.39
Cancelled prior to trust conversion	**(9)**	**9.61**	(22)	9.30
Cancelled immediately prior to trust conversion	**(1,184)**	**11.03**	–	–
Outstanding at end of year	**–**	**–**	1,297	7.05
Options exercisable at year end	**–**	**–**	985	6.25

STOCK-BASED COMPENSATION (SEE COMPENSATION EXPENSE TABLE ABOVE)

Compensation expense of $0.34 million was recognized for the 2004 year as a result of regular vesting of unvested stock options prior to the Arrangement. Additionally, as a result of cancelling the stock-option plan pursuant to the Arrangement, compensation expense for the year ended December 31, 2004 of $2.17 million resulted from accelerating of unvested stock options. Both of these non-cash expenses have been recognized as part of unit-based compensation expense on the income statement for the twelve month period.

Under this stock-option plan, the Company had calculated the value of stock-based compensation using a Black-Scholes option-pricing model to estimate the fair value of stock options at the date of grant.

Compensation expense for options granted under the stock option plan was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option.

The assumptions made for the options granted in 2004 include an annualized volatility factor of 26.30 percent, a weighted average risk-free interest rate of 3.33 percent, no dividend yield and a weighted average expected life of options of four years.

For purposes of pro forma disclosures relating to 2002 stock option grants, the Company's net earnings for the year ended December 31, 2003 would be reduced by $0.21 million. Basic and diluted earnings per share figures would have both been reduced by $0.01 for the 2003 year. There is no effect in 2004 pertaining to 2002 stock option grants because the options were fully vested prior to 2004.

TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a unit rights incentive plan (the "Plan") that allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The Trust is authorized to issue up to 1.82 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not at any time exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. At the time of grant, unit right exercise prices approximate the market price for the trust units. At the time of exercise the rights holder has the option of exercising at the original grant price or the exercise price as calculated per the Arrangement. Rights granted under the plan vest over a three-year period and expire five years from the grant date.

The following table summarizes information about the Trust's unit rights:

	December 31, 2004	
	Number of Unit Rights (thousand)	Weighted Average Exercise Price ($/unit right)
Outstanding at beginning of year	–	–
Unit rights granted	579	17.79
Outstanding at end of year	579	17.79
Unit rights exercisable at year end	–	–

The following table summarizes information about unit rights outstanding at December 31, 2004:

	Unit Rights Outstanding			Unit Rights Exercisable	
Range of Exercise Prices ($/unit right)	Number Outstanding at 12/31/04 (thousand)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($/unit right)	Number Exercisable at 12/31/04 (thousand)	Weighted Average Exercise Price ($/unit right)
17.70	546	4.1 years	17.70	–	–
19.25	33	4.1 years	19.25	–	–
	579		17.79	–	–

UNIT-BASED COMPENSATION (SEE COMPENSATION EXPENSE TABLE ABOVE)

The Plan allows for the exercise price of rights to be reduced in future periods by a portion of the future distributions. The Trust has determined that the amount of the reduction cannot be reasonably estimated, as it is dependent upon a number of factors including, but not limited to, future oil and natural gas prices, production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures, and the purchase and sale of oil and natural gas assets. Therefore, it is not possible to determine a fair value for the rights granted under the Plan.

Compensation expense is therefore determined based on the amount that the market price of the trust unit exceeds the original exercise price (grant price) for rights issued as at the date of the interim consolidated financial statements and is recognized in earnings over the vesting period of the Plan. Compensation expense for the unit rights for the year ended December 31, 2004 was $1.17 million.

Compensation expense associated with rights granted under the Plan is recognized in earnings, on a straight-line basis, over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in earnings in the period of change with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights is recorded as an increase in trust units with a corresponding reduction in contributed surplus. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights outstanding at the date of the financial statements.

The following table summarizes information about the Trust's contributed surplus account:

CONTRIBUTED SURPLUS
($ thousand)

Balance, December 31, 2002	–
Stock-based compensation expense for 2003	264
Balance, December 31, 2003	264
Stock-based compensation expense prior to Plan of Arrangement July 15, 2004	345
Stock-based compensation recognized on exercise of stock options	(69)
Accelerated vesting of unvested stock options pursuant to the Arrangement	2,167
Stock-options cancelled immediately prior to trust conversion	(2,707)
Balance at trust conversion	–
Unit-based compensation recognized subsequent to trust conversion	1,170
Balance, December 31, 2004	1,170

8. Non-Controlling Interest – Exchangeable Shares

Zargon Oil & Gas Ltd. is authorized to issue a maximum of 3.66 million exchangeable shares. The exchangeable shares are convertible into trust units at the option of the shareholder based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares. During the year, a total of 474,000 exchangeable shares were converted into 475,000 trust units based on the exchange ratio at the time of conversion. At December 31, 2004, the exchange ratio was 1.02583 trust units per exchangeable share. As set out in the Arrangement, the exchangeable shares are entitled to vote equally to the number of trust units for which each exchangeable share is convertible into a trust unit on the record date. The Board of Directors of Zargon Oil & Gas Ltd. hold the option to redeem all outstanding exchangeable shares for trust units on or before July 15, 2014. At such time, should the Board not extend the term of the shares, there will be no remaining non-controlling interest.

The Trust retroactively applied EIC-151 "Exchangeable Securities Issued by a Subsidiary of an Income Trust" in 2004. Per EIC-151, if certain conditions are met, the exchangeable shares issued by a subsidiary must be reflected as non-controlling interest on the consolidated balance sheet and in turn, net earnings must be reduced by the amount of net earnings attributed to the non-controlling interest.

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares at the time of the Plan of Arrangement, plus net earnings attributable to the exchangeable shareholders, less exchangeable shares (and related cumulative earnings) redeemed. The net earnings attributable to the non-controlling interest on the consolidated statement of earnings represents the cumulative share of net earnings attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end.

NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

	December 31, 2004	
(thousand, except exchange ratio)	Number of Shares	Amount ($)
Non-controlling interest – exchangeable shares issued		
Issued pursuant to Plan of Arrangement July 15, 2004	3,660	8,917
Exchanged for trust units at book value and including earnings attributed since Plan of Arrangement	(474)	(1,258)
Earnings attributable to non-controlling interest	–	1,870
Balance, end of year	3,186	9,529
Exchange ratio, end of year	1.02583	
Trust units issuable upon conversion of exchangeable shares, end of year	3,268	

The proforma total units outstanding at year-end, including trust units outstanding, and trust units issuable upon conversion of exchangeable shares and after giving rise to the exchange ratio at the end of the year is 18.61 million units.

9. Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its Canadian taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no current tax provision for Canadian income tax expense has been made in the Trust. Canadian Large Corporations tax, capital taxes and U.S. income taxes are provided for under current income tax expense.

In the Trust structure, payments are made between the Company and the Trust that result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company that would be recognized as a recovery of income tax in the period incurred.

Income taxes differ from the amounts that would be obtained by applying statutory income tax rates to earnings before income taxes as follows:

($ thousand)	2004	2003 (restated – note 3)
Statutory income tax rate	**39.96%**	41.58%
Expected income taxes	**13,289**	14,118
Add (deduct) income tax effect of:		
Non-deductible Crown charges, net of Alberta Royalty Tax Credit	**4,928**	3,856
Resource allowance	**(4,438)**	(4,724)
Rate adjustment	**947**	(4,314)
Cash distributions	**(4,277)**	-
Large corporation tax, capital taxes, and U.S. income taxes	**1,114**	406
Other	**(810)**	251
	10,753	9,593

As at December 31, 2004, Zargon has exploration and development costs, unamortized petroleum and natural gas property expenditures, undepreciated capital costs and unamortized share issue costs available for deduction against future taxable earnings in aggregate of approximately $79 million (December 31, 2003 – $79 million).

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of Zargon's net future income tax liability are as follows:

($ thousand)	2004	2003 (restated – note 3)
Net book value of property and equipment in excess of tax pools	**33,279**	19,501
Deferred partnership earnings	**14,153**	13,637
Asset retirement obligation	**(5,107)**	(2,211)
Non-capital loss carry forwards	**–**	(395)
Share issue costs	**(126)**	(240)
Alberta royalty tax deduction	**(369)**	(159)
	41,830	30,133

10. Weighted Average Number of Total Units

(thousand)	2004 (units)	2003 (shares)
Basic	**16,818**	17,824
Diluted	**18,723**	18,373

Dilution amounts of 1,905,000 (2003 – 549,000) were added to the weighted average number of units/common shares outstanding during the year in the calculation of diluted per unit/common share amounts. These unit/share additions represent the dilutive effect of unit rights/stock options according to the treasury stock method, and also include exchangeable shares using the "if-converted" method. In 2004, an adjustment to the numerator amount was required in the diluted calculation to provide for the earnings ($1.87 million) attributable to the non-controlling interest pertaining to the exchangeable shareholders.

11. Financial Instruments

FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

Financial instruments of the Trust consist of accounts receivable, deposits, accounts payable and accrued liabilities, bank indebtedness, and cash distributions payable. As at December 31, 2004 and 2003, there are no significant differences between the carrying values of these amounts and their estimated market values.

CREDIT RISK MANAGEMENT

Accounts receivable include amounts receivable for petroleum and natural gas sales that are generally made to large credit-worthy purchasers, and amounts receivable from joint venture partners that are recoverable from production. Accordingly, the Trust views credit risks on these amounts as low. Of Zargon's significant individual accounts receivable at December 31, 2004, approximately 28 percent was owing from one company (2003 – 21 percent).

The Trust is exposed to losses in the event of non-performance by counterparties to hedge transactions. The Trust minimizes credit risk associated with possible non-performance to these financial instruments by entering into contracts with only investment grade counterparties, limits on exposures to any one counterparty, and monitoring procedures. The Trust believes these risks are minimal.

INTEREST RATE RISK MANAGEMENT

Borrowings under bank credit facilities are for short periods and are market-rate-based (variable interest rates); thus carrying values approximate fair values.

FOREIGN CURRENCY RISK MANAGEMENT

The Trust is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil, and to a large extent natural gas prices, are based upon reference prices denominated in U.S. dollars, while the majority of the Trust's expenses are denominated in Canadian dollars. When appropriate, the Trust enters into agreements to fix the exchange rate of Canadian dollars to U.S. dollars in order to manage this risk.

COMMODITY PRICE RISK MANAGEMENT

The Trust enters into hedge transactions on oil and natural gas. The agreements entered into are forward transactions providing the Trust with a range of fixed prices on the commodities sold.

The Trust has outstanding contracts at December 31, 2004 and 2003 as follows:

At December 31, 2004	Volume	Rate	Price	Range of Terms
Financial Hedges				
Oil swaps	27,000 bbl	300 bbl/d	$35.45 US/bbl	Jan. 1/05–Mar. 31/05
	146,000 bbl	400 bbl/d	$44.05 US/bbl	Jan. 1/05–Dec. 31/05
Oil collars	54,300 bbl	300 bbl/d	$43.50 Cdn/bbl Put $54.50 Cdn/bbl Call	Jan. 1/05–Jun. 30/05
	55,000 bbl	200 bbl/d	$37.00 US/bbl Put $44.40 US/bbl Call	Apr. 1/05–Dec. 31/05
	36,200 bbl	200 bbl/d	$36.00 US/bbl Put $48.40 US/bbl Call	Jan. 1/06–Jun. 30/06
Natural gas swaps	180,000 gj	2,000 gj/d	$6.27/gj	Jan. 1/05–Mar. 31/05
	856,000 gj	4,000 gj/d	$6.49/gj	Apr. 1/05–Oct. 31/05
Natural gas collars	180,000 gj	2,000 gj/d	$6.75/gj Put $9.55/gj Call	Jan. 1/05–Mar. 31/05
	180,000 gj	2,000 gj/d	$6.75/gj Put $9.80/gj Call	Jan. 1/05–Mar. 31/05
	453,000 gj	3,000 gj/d	$5.90/gj Put $10.00/gj Call	Nov. 1/05–Mar. 31/06
	428,000 gj	2,000 gj/d	$6.00/gj Put $8.01/gj Call	Apr. 1/05–Oct. 31/05
Natural gas put	428,000 gj	2,000 gj/d	$5.10/gj	Apr. 1/05–Oct. 31/05
Physical Hedges				
Natural gas swaps	180,000 gj	2,000 gj/d	$8.35/gj	Jan. 1/05–Mar. 31/05
Natural gas put	428,000 gj	2,000 gj/d	$6.05/gj	Apr. 1/05–Oct. 31/05

At December 31, 2003	Volume	Rate	Price	Range of Terms
Financial Hedges				
Oil swaps	36,400 bbl	200 bbl/d	$26.44 US/bbl	Jan. 1/04–Jun. 30/04
	36,800 bbl	200 bbl/d	$27.10 US/bbl	Jul. 1/04–Dec. 31/04
Oil collars	36,400 bbl	200 bbl/d	$22.50 US/bbl Put $26.85 US/bbl Call	Jan. 1/04–Jun. 30/04
	36,400 bbl	200 bbl/d	$24.00 US/bbl Put $27.65 US/bbl Call	Jan. 1/04–Jun. 30/04
	36,800 bbl	200 bbl/d	$24.00 US/bbl Put $27.80 US/bbl Call	Jul. 1/04–Dec. 31/04
Natural gas swaps	364,000 gj	4,000 gj/d	$7.21/gj	Jan. 1/04–Mar. 31/04
	856,000 gj	4,000 gj/d	$5.15/gj	Apr. 1/04–Oct. 31/04
Natural gas collars	91,000 gj	1,000 gj/d	$5.50/gj Put $7.90/gj Call	Jan. 1/04–Mar. 31/04
	428,000 gj	2,000 gj/d	$5.00/gj Put $6.85/gj Call	Apr. 1/04–Oct. 31/04
Natural gas put	273,000 gj	3,000 gj/d	$5.00/gj	Jan. 1/04–Mar. 31/04

Oil swaps and collars are settled against the NYMEX pricing index, whereas natural gas swaps, collars and puts are settled against the AECO pricing index.

At December 31, 2004, $1.14 million would have been received to settle the above contracts and, of this amount $0.71 million related to financial hedges and $0.43 million related to physical hedges. At December 31, 2003, the cost to settle the above contracts would have been $0.89 million. These instruments have no book values recorded in the consolidated financial statements.

12. Commitments

The Trust is committed to future minimum payments for natural gas transportation contracts in addition to operating leases for office space, office equipment, vehicles and field equipment. Payments required under these commitments for each of the next four years are: 2005 – $1.88 million; 2006 – $0.71 million; 2007 – $0.43 million; 2008 – $0.07 million; and thereafter $0.03 million.

13. Contingencies and Guarantees

In the normal course of operations, Zargon executes agreements that provide for indemnification and guarantees to counterparties in transactions such as the sale of assets and operating leases.

These indemnifications and guarantees may require compensation to counterparties for costs and losses incurred as a result of various events, including breaches of representations and warranties, loss of or damages to property, environmental liabilities or as a result of litigation that may be suffered by counterparties.

Certain indemnifications can extend for an unlimited period and generally do not provide for any limit on the maximum potential amount. The nature of substantially all of the indemnifications prevents the Trust from making a reasonable estimate of the maximum potential amount that might be required to pay counterparties as the agreements do not specify a maximum amount, and the amounts depend on the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time.

The Trust indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Trust to the extent permitted by law. The Trust has acquired and maintains liability insurance for its directors and officers. The Trust is party to various legal claims associated with the ordinary conduct of business. The Trust does not anticipate that these claims will have a material impact on the Trust's financial position.

14. Supplemental Cash Flow Information

($ thousand)	2004	2003
Cash interest paid	**448**	714
Cash taxes paid	**794**	360

15. Segmented Information

Zargon's entire operating activities are related to exploration, development and production of oil and natural gas in the geographic segments of Canada and the U.S.

	2004		
($ thousand)	Canada	United States	Combined
Petroleum and natural gas revenue	**108,484**	**15,484**	**123,968**
Property and equipment	**184,860**	**24,876**	**209,736**
Total assets	**200,171**	**26,793**	**226,964**
Net capital expenditures	**51,464**	**4,809**	**56,273**

($ thousand) (restated – note 3)	2003 Canada	United States	Combined
Petroleum and natural gas revenue	90,034	11,623	101,657
Property and equipment	145,210	22,678	167,888
Total assets	157,583	23,468	181,051
Net capital expenditures	33,373	6,536	39,909

16. Accumulated Cash Distributions

During the year, the Trust paid or declared distributions to the unitholders in the aggregate amount of $10.70 million (2003 – $nil) in accordance with the following schedule:

Month	Record Date	Distribution Date	Per Trust Unit
August 2004	August 31, 2004	September 15, 2004	$0.14
September 2004	September 30, 2004	October 15, 2004	$0.14
October 2004	October 31, 2004	November 15, 2004	$0.14
November 2004	November 30, 2004	December 15, 2004	$0.14
December 2004	December 31, 2004	January 17, 2005	$0.14

17. Zargon Energy Trust Reorganization

The following costs were incurred to reorganize Zargon Oil & Gas Ltd. into a trust, effective July 15, 2004:

($ thousand)	
Cash payout of stock options	7,875
Financial advisory, accounting and legal fees, and preparation and printing of the Information Circular	1,568
Total reorganization costs	9,443

Of the above amounts, $2.71 million was charged to contributed surplus relating to recognized stock-based compensation under the previous stock option plan for the Company. The remaining $6.73 million ($6.24 million net of taxes) was charged directly against accumulated earnings.

18. Related Party Transactions

During the year, Zargon paid $0.15 million in consulting fees to a company owned by the Chairman of the Board; $0.05 million for vehicle leases to a company owned by a Board member; and $0.53 million for legal services in conjunction with the Arrangement to a law firm in which a Board member is a partner. These payments were in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount.

19. Comparative Figures

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

six-year financial and operating summary

	2004	2003	2002	2001	2000	1999
FINANCIAL ($ thousand, except per unit amounts)						
Petroleum and natural gas revenue	**123,968**	101,657	65,538	63,795	53,306	24,048
Less expenses – cash items						
Royalties (net of Alberta Royalty Tax Credit)	**28,047**	22,508	13,508	14,222	10,716	4,033
Production	**21,692**	17,201	15,649	11,933	8,615	6,120
General and administrative (net)	**4,358**	3,542	3,455	3,083	2,189	1,463
Hedging	**4,568**	2,882	(669)	573	2,733	1,095
Interest	**440**	771	1,100	957	1,269	592
Current and capital taxes	**1,114**	406	378	358	288	103
Cash flow from operations	**63,749**	54,347	32,117	32,669	27,496	10,642
Less expenses – non-cash items						
Depletion, depreciation and foreign exchange	**26,850**	19,363	14,148	11,067	7,061	5,041
Future income tax	**9,639**	9,187	6,558	7,860	8,706	1,035
Accretion	**1,076**	1,172	715	520	479	323
Unit-based compensation	**3,682**	264	–	–	–	–
Earnings before non-controlling interest	**22,502**	24,361	10,696	13,222	11,250	4,243
Less non-controlling interest – exchangeable shares	**1,870**	–	–	–	–	–
Net earnings	**20,632**	**24,361**	**10,696**	**13,222**	**11,250**	**4,243**
Per unit, diluted						
Cash flow ($/unit)	**3.40**	2.96	1.81	2.03	1.86	0.70
Net earnings ($/unit)	**1.20**	1.33	0.60	0.82	0.76	0.29
Net capital expenditures	**56,273**	39,909	35,548	55,176	30,514	16,945
Cash distributions	**10,702**	–	–	–	–	–
Cash distributions ($/trust unit)	**0.70**	–	–	–	–	–
Balance sheet at year end						
Property and equipment, net	**209,736**	167,888	147,404	124,020	78,030	54,280
Bank and other debt	**14,230**	6,978	25,279	24,137	15,902	14,116
Unitholders' equity	**120,622**	112,469	86,699	70,072	42,510	32,505
Unitholders' equity ($/total units)	**6.48**	6.25	4.92	4.20	2.97	2.25
Weighted average units outstanding - total (thousand)	**18,455**	17,824	17,233	15,558	14,408	14,686
Year-end total units outstanding (thousand)	**18,610**	17,992	17,637	16,666	14,315	14,420
OPERATIONS						
Total production (boe/d)	**8,222**	7,446	6,349	5,553	4,140	3,236
Oil and liquids (bbl/d)	**3,416**	3,287	2,968	2,441	1,725	1,711
Natural gas (mmcf/d)	**28.84**	24.95	20.29	18.67	14.49	9.15
Equivalent per million total units (boe/d)	**447**	418	368	357	287	224
Total proved reserves (mboe)	**19,049**	18,664	21,592	20,320	15,878	12,090
Proved oil and liquids (mbbl)	**10,954**	10,505	11,114	10,482	6,340	5,210
Proved natural gas (bcf)	**48.57**	48.96	62.87	59.03	57.23	41.28
Total proved and probable reserves (mboe)	**25,955**	24,745	23,983	22,859	18,343	13,964
Proved and probable oil and liquids (mbbl)	**14,361**	13,566	12,445	11,948	7,508	6,150
Proved and probable natural gas (bcf)	**69.56**	67.07	69.23	65.47	64.96	46.88
Equivalent per total unit – year end (boe)	**1.39**	1.38	1.36	1.37	1.28	0.97
Average selling prices (before hedges)						
WTI crude oil price ($US/bbl)	**41.40**	31.04	26.08	25.90	30.20	19.24
FOB Edmonton crude oil price ($/bbl)	**52.54**	43.14	39.94	39.18	44.33	27.35
Zargon field oil price ($/bbl)	**45.37**	36.66	34.45	31.86	40.73	25.02
NYMEX Henry Hub Price ($US/mmbtu)	**5.90**	5.49	3.35	3.94	4.31	2.27
Alberta AECO natural gas price ($/mmbtu)	**6.55**	6.70	4.18	5.43	5.60	2.92
Zargon field natural gas price ($/mcf)	**6.37**	6.33	3.81	5.19	5.20	2.52
Other Data						
Wells drilled, net	**49.5**	38.6	31.6	47.7	38.6	18.8
Undeveloped land (thousand net acres)	**376**	398	331	241	213	177
Closing trust unit price ($/unit)	**23.85**	13.50	9.00	7.20	4.45	3.00

Notes: Cash distributions to unitholders commenced subsequent to the reorganization of the Company into a Trust effective July 15, 2004.

Total units outstanding include trust units plus exchangeable shares outstanding at period end. The exchangeable shares are converted at the exchange ratio at the end of the period.

Average daily production per million units is calculated using the weighted average number of units outstanding during the period plus the weighted average number of exchangeable shares outstanding for the period converted at the exchange ratio at the end of the period.

In this table the established reserves (proved plus 50 percent probable) for the prior years (1999-2002) are used as a comparison to 2003 and 2004 proved and probable reserves. This adjustment is necessary due to the change in reserve risk assessments required to comply with NI 51-101 reserve guidelines.

Certain comparative period numbers reflect retroactive restatement due to a change in accounting policy.

corporate information

BOARD OF DIRECTORS

Craig H. Hansen
Calgary, Alberta

K. James Harrison (3)(4)
Oakville, Ontario

H. Earl Joudrie (3)
Toronto, Ontario

Kyle D. Kitagawa (1)
Calgary, Alberta

John O. McCutcheon
Vancouver, British Columbia

Jim D. Peplinski (2)(4)
Calgary, Alberta

Byron J. Seaman (1)
Calgary, Alberta

J. Graham Weir (1)(2)
Calgary, Alberta

William J. Whelan (1)(4)
Calgary, Alberta

Grant A. Zawalsky (2)(3)
Calgary, Alberta

OFFICERS

John O. McCutcheon
Chairman

Craig H. Hansen
President and Chief Executive Officer

Brent C. Heagy
Vice President, Finance and Chief Financial Officer

Mark I. Lake
Vice President, Exploration

Daniel A. Roulston
Executive Vice President, Operations

Sheila A. Wares
Vice President, Accounting

Kenneth W. Young
Vice President, Land

1 Audit Committee
2 Reserves Committee
3 Governance Committee
4 Compensation Committee

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Trading Symbols:
Trust units ZAR.UN
Exchangeable shares ZOG.B

TRANSFER AGENT

Valiant Trust Company
310, 606 – 4th Street S.W.
Calgary, Alberta T2P 1T1

BANKER

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Calgary, Alberta T2P 2P6

LEGAL COUNSEL

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Calgary, Alberta T2P 3N9

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Calgary, Alberta T2P 3G6

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ANNUAL MEETING

The annual meeting of the unitholders of Zargon Energy Trust will be held on Thursday, April 28, 2005 at 2:00 pm (Calgary time) in the Imperial Room of the Hyatt Regency Calgary, 700 Centre Street S.E., Calgary, Alberta.

ZARGON YEAR-END TRUST UNIT PRICE

FORWARD-LOOKING STATEMENTS

This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly actual results may differ materially from those predicted. The forward-looking statements contained in this annual report are as of March 14, 2005 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

ABBREVIATIONS

bbl	Barrel
bbl/d	Barrels per day
bcf	Billion cubic feet
boe	Barrels of oil equivalent (6 mcf is equivalent to 1 bbl)
boe/d	Barrels of oil equivalent per day
btu	British thermal units
FD&A	Finding, development and acquisition
gj	Gigajoule
gj/d	Gigajoules per day
m	Thousand
mm	Million
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
PV	Present value
PVBT	Present value before tax

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